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October 7, 2020

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: DEP Late-Filed Exhibit No. 3
Docket No. E-2, Sub 1219

Dear Ms. Campbell:

Per the request of the North Carolina Utilities Commission during the Duke Energy Progress, LLC ("DEP") evidentiary hearing held on September 29, 2020, enclosed for filing on behalf of DEP in the above-referenced proceeding is Late-Filed Exhibit No. 3. Late-Filed Exhibit No. 3 provides copies of retirement analyses and decommissioning studies for several DEP generation sites.

Please do not hesitate to contact me should you have any questions. Thank you for your assistance with this matter.

Very truly yours,

/s/Mary Lynne Grigg

MLG:kma

Enclosures

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
DEP Late-Filed Exhibit No. 3

Request: Sutton, Cape Fear, Weatherspoon, H.S. Lee & Robinson - Decommissioning/Retirement Analyses.

Response:
After a diligent search the Company has not identified any additional retirement analyses for these stations. In searching the Company's past legal proceedings, the following certificates of public convenience and necessity (CPCN), retirement plans, decommissioning studies were located.

In August 2009, as part of the CPCN approval process for the 950 MW Wayne County Combined Cycle Project ("Lee CC"), DEP proposed accelerating the retirement date of the three H.F. Lee coal units. The early retirement of the existing 400 MW of coal generation at the HF Lee site was facilitated by N.C. Gen. Stat. §62-110.1(h), which encouraged the replacement of the coal units with cleaner, more efficient, and more cost-effective natural gas-fired generation. North Carolina Session Law 2009-390, enacted in July 2009, amended G.S. 62-110.1 to add subsection (h):

> "(h) Notwithstanding any other subsections of this section to the contrary, the Commission shall render its decision on an application for a certificate within 45 days of the date the application is filed if (i) the public utility that has applied for the certificate is subject to the provisions of subsection (e) of G.S. 143-215.107D[1]; (ii) the application involves a request by the public utility to construct a generating unit that uses natural gas as the primary fuel at a specific coal-fired generating site that the public utility owns or operates on July 1, 2009; (iii) the coal-fired generating units at the site are not operated with flue gas desulfurization devices; (iv) the public utility will permanently cease operations of all of the coal-fired generating units at the site on or before the completion of the generating unit that is the subject of the certificate application; and (v) the installation of the generating unit that uses natural gas as the primary fuel allows the public utility to meet the requirements of subsection (e) of G.S. 143-215.107D. When the public utility applies for a certificate as provided in this subsection, it shall submit to the Commission and the Department of Environment and Natural Resources a revised verified statement required pursuant to subsection (i) of G.S. 62-133.6 and to the Commission an estimate of the costs of construction of the generating unit that uses natural gas as the primary fuel in such detail as the Commission may require. The provisions of G.S. 62-82 and subsection (e) of this section shall not apply to a certificate applied for pursuant to this subsection. The authority granted pursuant to this subsection expires January 1, 2011."

Consistent with this statute, on August 18, 2009, the Company (which at the time was Progress Energy Carolinas, Inc.) filed in Docket No. E-2, Sub 960 for a CPCN to construct the Wayne CC. Attachment 2 to

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[1] This statute, part of the North Carolina Clean Smokestacks Act of 2002, provided that "An investor-owned public utility that owns or operates coal-fired generating units that collectively emitted more than 225,000 tons of sulfur dioxide (SO_2) in calendar year 2000:

(1) Shall not collectively emit from the coal-fired generating units that it owns or operates more than 150,000 tons of sulfur dioxide (SO_2) in any calendar year beginning 1 January 2009.

(2) Shall not collectively emit from the coal-fired generating units that it owns or operates more than 80,000 tons of sulfur dioxide (SO_2) in any calendar year beginning 1 January 2013."

the application provided an economic analysis of constructing the CC versus investing in the required environmental controls at the coal units, which indicated that retirement was the most cost-effective path. The application including Attachment 2 is provided below:

Wayne County Lee
Combined Cycle Apr

The Commission granted the CPCN by its *Order Granting Certificate of Public Convenience and Necessity Subject to Conditions* issued Oct. 22, 2009 in that docket. In that Order, the Commission directed (consistent with G.S. 62-110.1(h)) that the Company permanently cease operation of the three coal-fired generating units at the HF Lee site, and also required the Company to submit for approval a plan to retire additional unscrubbed coal-fired generating capacity reasonably proportionate to the amount of incremental generating capacity authorized by the CPCN above 400 MW.

On December 1, 2009, the Company filed its plan to retire an additional approximately 500 MW of coal units at the Cape Fear and Weatherspoon plants. The Company explained that the most prudent course of action, given that it would have been required to make significant investments to install additional environmental controls control emissions of nitrogen oxides (NOx), sulfur dioxide (SO2), mercury (Hg), and greenhouse gases (GHGs) on coal-fired units with an average in-service life of more than 50 years, was to retire and replace these units. The incremental 550 MW of generation available at the Wayne CC could be used to replace these units, so they were planned for retirement after the Wayne CC was placed in service. The Company also explained that it had reached the same conclusion to retire Sutton station, but due to voltage requirements in the Wilmington area and associated with the Company's Brunswick Nuclear Plant, would need to replace Sutton's capacity with a new gas fired generation facility at that location. The Dec. 1, 2009 retirement plan is provided below:

CPCN - PEC
Retirement Plan.pdf

In its January 28, 2010 *Order Approving Plan* in Docket No. E-2, Sub 960, the NCUC approved DEP's plan to retire approximately 500 MW of coal generation at the Cape Fear and Weatherspoon plants.

On Dec. 18, 2009, in Docket No. E-2, Sub 968, the Company filed for Commission approval of a CPCN to construct the 620 MW combined cycle facility at the Sutton Plan site, to replace the retiring coal units at Sutton per the retirement plan. In the application, the Company described the economic analysis of continued operations of Sutton versus replacement with a CC in the application, which indicated the retirement was the most cost-effective path:

The Commission granted the Company's request in its *Order Issuing Certificate of Public Convenience and Necessity* issued June 9, 2010. The order directed the Company to permanently cease operation of the three coal-fired units at Sutton immediately upon completion a displacement in service of the Sutton CC.

Sutton Combined
Cycle Application.pc

The Company's coal units, Cape Fear, Lee, Sutton, Robinson and Weatherspoon, retired on the following dates:

DEP Retired Units				
Unit	**Function**	**Fuel**	**In-Service Year**	**Retired Year**
Cape Fear Unit 5	Steam	Coal	1956	2012
Cape Fear Unit 6	Steam	Coal	1958	2012
H. F. Lee Unit 1	Steam	Coal	1952	2012
H. F. Lee Unit 2	Steam	Coal	1951	2012
H. F. Lee Unit 3	Steam	Coal	1962	2012
Robinson Unit 1	Steam	Coal	1960	2012
Sutton Unit 1	Steam	Coal	1954	2013
Sutton Unit 2	Steam	Coal	1955	2013
Sutton Unit 3	Steam	Coal	1972	2013
Weatherspoon Unit 1	Steam	Coal	1949	2011
Weatherspoon Unit 2	Steam	Coal	1950	2011
Weatherspoon Unit 3	Steam	Coal	1952	2011

Decommissioning studies addressing these units are attached below:

- 2012 Near term decommissioning study for Cape Fear, Lee, Sutton, and Weatherspoon:

  FINAL_Progress
  Carolinas Decommis

- 2012 Decommissioning study for Robinson:

  FINAL_Progress
  Carolinas Decommis

Progress Energy Carolinas, Inc.'s CPCN Application for Wayne County CC filed August 18, 2009 in Docket No. E-2, Sub 960

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Progress Energy

OFFICIAL COPY

FILED
AUG 18 2009
Clerk's Office
N.C. Utilities Commission

RECEIVED FILING FEE $250.00

August 18, 2009

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

RE: Docket No. E-2, Sub 960

Enclosed for filing with the Commission are the original and 30 copies of Progress Energy Carolinas, Inc.'s Application for a Certificate of Public Convenience and Necessity to Construct a 950 Megawatt Combined Cycle Natural Gas Fueled Electric Generation Facility in Wayne County near the City of Goldsboro and Motion for Waiver of Commission Rule R8-61. Attachment 4 to this filing contains confidential information regarding the construction and operating costs of the proposed facility. The original and ten copies of the unredacted version of Attachment 4 are attached in a sealed envelope marked "Confidential." PEC requests that the unredacted version be treated confidentially pursuant to N.C. Gen. Stat. § 132-1.2. Public disclosure of this information would harm PEC's ability to negotiate favorable contracts for equipment and services, as well as purchased power contracts, because potential vendors would know the amounts PEC is willing to pay for such products and services.

Also enclosed is a check in the amount of $250.00.

Yours very truly,

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

(20)
w/confid.
w/confid.

LSA:mhm

STAREG569

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

BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 960

In the Matter of Application of Progress Energy Carolinas, Inc. for a Certificate of Public Convenience and Necessity to Construct a 950 Megawatt Combined Cycle Natural Gas Fueled Electric Generation Facility in Wayne County near the City of Goldsboro and Motion For Waiver of Commission Rule R8-61	**APPLICATION OF PROGRESS ENERGY CAROLINAS, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT A 950 MEGAWATT COMBINED CYCLE NATURAL GAS FUELED ELECTRIC GENERATION FACILITY IN WAYNE COUNTY NEAR THE CITY OF GOLDSBORO AND MOTION FOR WAIVER OF COMMISSION RULE R8-61**

Pursuant to N.C. Gen. Stat. § 62-110.1(h) and § 62-300, and North Carolina Utilities Commission ("the Commission") Rules R1-3, R1-5, and R1-7, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. ("PEC") applies to the Commission for a Certificate of Public Convenience and Necessity to construct a 950 megawatt ("MW") combined cycle natural gas fueled electric generation facility at its existing generation site in Wayne County near the City of Goldsboro and moves the Commission to waive the requirements of Commission Rule R8-61.[1] In support thereof, PEC shows the following:

1. PEC is an electric public utility organized, existing and operating under the laws of North Carolina for the purposes of generating, transmitting and

[1] The proposed natural gas fueled facility will operate primarily on natural gas but will be capable of burning no. 2 fuel oil.

distributing electricity in its service territories in North and South Carolina. Its principal offices are located at 410 S. Wilmington Street, Post Office Box 1551, Raleigh, NC 27602.

2. The attorneys to whom all communications and pleadings should be addressed are:

Len S. Anthony
General Counsel
P. O. Box 1551, PEB 17A4
Raleigh, NC 27602

Dwight W. Allen
The Allen Law Offices, PLLC
3737 Glenwood Avenue, Suite 100
Raleigh, North Carolina 27612

3. PEC incorporates by reference its September 2, 2008 Annual Resource Plan, filed with the Commission in Docket No. E-100, Sub 118.

4. N.C. Gen. Stat. § 62-110.1(h) provides that an electric public utility may apply for an expedited certificate of public convenience and necessity if: the utility is subject to N.C. Gen. Stat. § 143-215.107D(e); the application involves a request to construct a generating unit that uses natural gas as its primary fuel at a specific coal-fired generating site that the utility owns or operates on July 1, 2009; the coal fired-units at the site are not operated with flue gas desulfurization devices; the utility will permanently cease operations of all of the coal-fired generating units at the site on or before the completion of the generating unit that is the subject of the certificate application; and the installation of the generating unit

that uses natural gas as the primary fuel allows the utility to meet the requirements of N.C. Gen. Stat. § 143-215.107D(e). N.C. Gen. Stat. § 62-110.1(h) further provides that subsection (e) of N.C. Gen. Stat. § 62-110.1 and § 62-82 do not apply to a certificate filed pursuant to N.C. Gen. Stat. § 62-110.1(h).

5. The Clean Smokestacks Act ("CSA"), in particular, N.C. Gen. Stat. § 143-215.107D(e), provides that beginning in calendar year 2013, PEC must reduce its annual emissions of sulfur dioxide ("SO_2") from its North Carolina coal-fueled generating units from 100,000 tons to 50,000 tons. As reflected in PEC's annual reports to the Commission and the Department of Environment and Natural Resources ("DENR") filed pursuant to N.C. Gen. Stat. § 62-133.6(i), PEC had tentatively determined that scrubbing approximately 400 MWs of its existing uncontrolled coal fueled generation (in particular unit 3 at its Sutton coal fueled plant, a 403 MW unit, located near Wilmington), was the most appropriate means of meeting this requirement.

6. PEC continuously evaluates the most robust and cost effective means of complying with all environmental requirements, including the CSA. PEC also considers the cost of complying with potential new or revised environmental laws or regulations. Such potential new or revised environmental requirements include but are not limited to a "point source" Environmental Protection Agency ("EPA") Clean Air Interstate Rule ("CAIR"), a North Carolina mercury rule, and federal greenhouse gas emissions legislation.

7. Through this process PEC evaluated ceasing operations of the three coal units (397 MWs) at its Lee Plant located on the Neuse River in Wayne County near the City of Goldsboro and replacing them with a natural gas fueled combined cycle unit as means to meet the 2013 CSA requirements and position PEC to comply with any new or revised environmental requirements. None of the Lee coal units have any form of flue gas desulfurization device. Attachment 1 to this Application (PEC's revised 2008 CSA Annual Report) demonstrates that replacing these coal units with a natural gas facility will allow PEC to achieve compliance with the CSA in 2013. As shown in Attachment 2, consistent with the findings of the North Carolina General Assembly in Senate Bill 1004 that replacing coal fueled generation with natural gas fueled generation reduces emissions of SO_2, mercury ("Hg"), oxides of nitrogen ("NOx") and carbon dioxide ("CO_2") more than installation of SO_2 controls, replacing the Lee coal fueled generation units with natural gas generation is more cost effective than installing additional air emissions controls to achieve compliance with the potential new environmental regulations described above.

8. PEC considered ceasing operations of Unit 3 at its Sutton Plant and replacing it with a natural gas fueled plant, rather than ceasing operations of the three Lee Plant coal units. However, ceasing operations of the Lee Plant coal units is the more prudent course of action because the natural gas delivery infrastructure necessary to support a natural gas fueled facility at the Lee Plant site can be

constructed and in service by January 1, 2013. This may not be the case for the Sutton Plant site.

9. Natural gas fueled generation may consist of one or more combustion turbines ("CTs") standing alone or combined with one or more heat recovery steam generators and steam turbines. When combined with a heat recovery steam generator and a steam turbine the facility is known as a combined cycle facility ("CC"). The heat recovery steam generator captures the waste exhaust heat from the combustion of natural gas in the CT to produce steam, which is then flowed through the steam turbine to produce additional electricity. Since CCs use energy (exhaust heat) that would otherwise be wasted, they are more efficient than CTs and are more cost effective for intermediate load operation.

10. Standing alone, a CT is referred to as operating in simple cycle mode. PEC could replace the 397 MWs of coal fueled generating capacity at the Lee Plant with two simple cycle CTs (each with a generating capacity of approximately 190 MW). However, this would not be the optimum resource to replace the existing coal plants because the existing coal fueled units are used as an intermediate type load following resource to meet the electricity needs of PEC's customers. Their typical annual capacity factors are in the range of 40%-50%. In contrast, simple cycle CTs are not cost effective compared to CCs at capacity factors above 10%-15%. Therefore, PEC proposes to construct a CC rather than two CTs.

11. The existing site can support either a 3x1 CC or a 2x1 CC. A 2x1 CC consists of two CTs connected to two heat recovery steam generators and a steam turbine. Its total generating capacity would be approximately 650 MWs. A 3x1 CC consists of three CTs connected to three heat recovery steam generators and a steam turbine. Its total generating capacity would be approximately 950 MW. A 2x1 CC will produce electricity at a levelized busbar cost of $161/MWH at a 40% capacity factor. A 3x1 CC will produce electricity at a levelized busbar cost of $147/MWH at a 40% capacity factor. Levelized busbar cost reflects the cost of producing electricity up to the point of the power plant busbar including the unit capital cost, fixed and variable costs, fuel costs, and cost of capital levelized over the life of the generating facility. As demonstrated by Attachment 3, a 3x1 CC has a lower busbar cost per kwh than a 2x1 and, as further explained below, given the site's characteristics, is the best natural gas fueled resource to replace the existing coal fueled units.

12. The construction of a 3x1 CC will optimize the existing plant's main condenser cooling water supply and transmission infrastructure. A 3x1 CC will also not significantly change the main condenser cooling water supply flow rate or thermal loading at the site. Transmission analyses indicate that both a 2x1 CC and a 3x1 CC will require approximately the same transmission upgrades, yet the 3x1 CC will result in an approximately 300 MW incremental increase in unit capacity without any significant additional transmission investment.

13. Construction of a 950 MW natural gas fueled CC to replace the 397 MW Lee Plant coal units will result in approximately 550 MW of incremental capacity. This incremental capacity may be used for a number of purposes including the replacement and closure of some of the remaining older coal units owned by PEC in North Carolina that do not have any SO_2 controls. This incremental capacity could also be used to meet load growth and displace or defer other planned additions in PEC's resource plan. Another option would be to operate the gas fired CC generation to displace coal fired generation depending upon the relative costs of natural gas and coal, but without closing the coal fueled units. If PEC does not use the incremental capacity to close additional uncontrolled coal units, PEC's capacity margin in 2013 is estimated to be 16% and then decline thereafter. PEC's target capacity margin is 11-13%. While in this situation PEC's capacity margin may temporarily exceed PEC's target, PEC's customers will not experience any base rate impact unless and until the Commission rules upon the justness and reasonableness of the facility's costs.

14. PEC therefore applies to the Commission for a certificate of public convenience and necessity pursuant to N.C. Gen. Stat. § 62-110.1(h) to construct a 3x1 CC that uses natural gas as its primary fuel near the Lee Plant in Wayne County. If allowed to construct this natural gas fueled facility, upon its completion, PEC will permanently cease operations of the three coal fueled generating units totaling 397 MWs at its Lee Plant. As mentioned above, none of

these existing coal units have any form of flue gas desulfurization device. The replacement of these three coal fueled units totaling 397 MWs with the proposed natural gas fueled facility will allow PEC to meet its requirements under N.C. Gen. Stat. § 143-215.107D(e).

15. In addition to reducing PEC's emissions of SO_2, NOx, and Hg, ceasing operations of the three Lee coal units and replacing them with a 3x1 CC will reduce PEC's annual emission of CO_2 by approximately 1.1 million tons.

16. As required by N.C. Gen. Stat. § 62-110.1(h), included with this Application as Attachments 1 and 4 respectively are: a revised verified Calendar Year 2008 Clean Smokestacks Report, revised to reflect the replacement of the three coal units at the Lee Plant site with a natural gas fueled facility and the elimination of a scrubber on Sutton Unit 3 in 2012; and an estimate of the construction costs of the proposed natural gas fueled facility, including the anticipated construction, testing and commercial operation schedule.

17. The primary environmental permit required before construction can begin on this project is the air permit. Because the project involves the retirement of the existing coal units, the air emissions from the proposed CC facility with the appropriate emission controls (e.g., oxidation catalyst) are expected to be substantially reduced. Therefore, the new permit application is expected to qualify as a "minor" permit proceeding. As a minor permit proceeding, the final air permit would be expected to be issued by the NC Division of Air Quality in 6 to 12

months following application submittal. Other environmental permitting will be required for modification of the facility's National Pollutant Discharge Elimination System (NPDES) permit. Conditions of the revised NPDES permit may address closure requirements for the Lee Plant's ash pond. A county development permit and a state Erosion & Sedimentation Control Plan will need to be approved for site development. If wetlands are impacted, a U.S. Army Corps of Engineers Dredge & Fill permit will be required. FAA notification of the height and location of the new emission stacks will be required. The facility's Spill Prevention, Control and Countermeasure Plan ("SPCC") and Emergency Response Plan will need to be revised.

18. All transmission line enhancements above 115 kV will occur and are primarily related to the substation bus and generation interconnection.

19. Ostensibly, Commission Rule R8-61 applies to this Application for a certificate of public convenience and necessity. However, compliance with this Rule, in particular the requirement to pre-file certain information 120 days prior to the filing of the actual application, would defeat the purpose of N.C. Gen. Stat. § 62-110.1(h). Therefore, PEC moves the Commission to waive Rule R8-61. PEC has consulted with the Public Staff on this matter and they have authorized PEC to represent to the Commission that they do not object to PEC's request for waiver and agree that the information included with this Application provides all information necessary for a proper evaluation of PEC's Application.

WHEREFORE, PEC applies to the Commission for a Certificate of Public Convenience and Necessity to construct a 950 megawatt combined cycle natural gas fueled electric generation facility near its existing Lee Plant in Wayne County near the City of Goldsboro and moves the Commission to waive the requirements of Commission Rule R8-61.

Respectfully submitted this 18th day of August, 2009.

PROGRESS ENERGY CAROLINAS, INC.

Len S. Anthony, General Counsel
P. O. Box 1551, PEB 17A4
Raleigh, NC 27602
Telephone: (919) 546-6367

Attachment 1

Progress Energy

August 17, 2009

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

Dear Secretary Freeman:

In accordance with amended G.S. 62-110.1, Progress Energy Carolinas, Inc. (PEC, Company) submits the attached revised report regarding the current status of and future plans for compliance with the provisions of the North Carolina Clean Smokestacks Act.

As I have noted before, we regularly review and refine our compliance strategy, weighing a number of factors such as system load projections, new natural gas supply, natural gas-fired generation options, coal unit retirements, updated load and energy forecasts, updated fuel costs, updated capital and operating costs, and federal and state environmental legislative and regulatory developments. As a result of recent resource planning studies taking all of these drivers into account, PEC has determined that retirement of a coal-fired plant and replacement of that plant with combined-cycle natural gas-fired units represents a cost- effective resource plan for our system. Accomplishing this retirement and replacement by 2013 eliminates the need for a sulfur dioxide scrubber on Sutton Unit 3 in order to comply with the 2013 Clean Smokestacks Act limits. This revised strategy is described in the attached updated Clean Smokestacks report.

I want to thank you and your staff for your assistance and support of SB 1004, which will help facilitate our plans for natural-gas fired generation. We look forward to continuing our positive working relationship with the Department to facilitate fulfillment of the Company's obligations with this important law.

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

Sincerely,

Caroline Choi
Director, Energy Policy and Strategy

c: North Carolina Utilities Commission
Keith Overcash, DAQ

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

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF WAKE)

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

That she is Paula Sims, Senior Vice President-Power Operations of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; she has the authority to verify the foregoing Progress Energy Carolinas, Inc. North Carolina Clean Smokestacks Act Calendar Year 2008 Progress Report - Revision; that she has read said revised Report and knows the contents thereof; are true and correct to the best of her knowledge and beliefs.

Paula Sims
Senior Vice President-Power Operations
Progress Energy Carolinas, Inc.

Subscribed and sworn to me
this 17 day of August, 2009.

Carol P. Penny
Notary Public

Revised 2008 CSA Report

Progress Energy Carolinas, Inc. (PEC)
North Carolina Clean Smokestacks Act
Calendar Year 2008 Progress Report

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

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

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

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

Under G.S. § 143-215.107D(f), "each investor-owned public utility...may determine how it will achieve the collective emissions limitations imposed by this section." PEC originally submitted its compliance plan on July 29, 2002. Appendix A contains an updated version of this plan, effective July 31, 2009. 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 2008, Progress Energy Carolinas, Inc. incurred actual capital costs of $114,164,000.

<u>Mayo</u>

Engineering, procurement, and construction work continued throughout 2008. Major accomplishments included completion of the absorber, completion of the chimney, beginning construction of the waste water treatment system, and beginning commissioning and start-up activities. At year end, the project was 83% complete. Construction occurred on schedule to support final tie-in of the scrubber in March, 2009 with initial operation in early April, 2009.

<u>Roxboro</u>

The scrubbers on Units 2 and 4 operated successfully throughout the year. Construction of the scrubbers on Units 1 and 3 was completed with Unit 3 going into service on May 6, 2008 and Unit 1 going into service on December 16, 2008. At the end of 2008, the Roxboro project was 96% complete.

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

Progress Energy Carolinas, Inc. amortized $15,000,000 in 2008.

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 2008 and the projected costs for future years through 2013. The costs shown are the net costs to PEC, excluding the portion for which the Power Agency is responsible. The estimated total capital costs, including escalation, are currently projected to be $1.068 billion. This represents a decrease of $334 million from the April 2009 cost estimate of $1.402 billion.

We regularly review and refine our compliance strategy, weighing a number of factors such as system load projections, new natural gas supply, natural gas-fired generation options, coal unit retirements, updated load and energy forecasts, updated fuel costs, updated capital and operating costs, and federal and state environmental legislative and regulatory developments. As a result of recent resource planning studies taking all of these drivers into account, PEC has determined that retirement of a coal-fired plant and replacement of that plant with a combined-cycle natural gas-fired unit represents a cost-effective resource plan for our system. Accomplishing this retirement and replacement by 2013 eliminates the need for a sulfur dioxide scrubber on Sutton Unit 3 in order to comply with the 2013 Clean Smokestacks Act limits.

With this plan, additional controls are not needed at Sutton 3 to meet the 2013 Clean Smokestacks Act limits, therefore that unit is no longer shown in Appendix B and the compliance costs have been reduced accordingly.

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 applied for or received the following permits in 2008:

Roxboro Plant

Air Permit

Agency approval was received on April 23, 2008, which incorporated revised limits for SO_2 and NOx based on scrubber stack dispersion analysis.

Authorization to Construct

A request for an Authorization to Construct for revisions to the waste water system to temporarily reroute the backwash discharge line from the flush pond to the settling pond was submitted on April 10, 2008 and approved on April 18, 2008.

Mayo Plant

Erosion and Sediment Control Plan

Revision I to the Erosion and Sediment Control Plan for an increase in disturbed land for additional lay down area for the flue gas desulfurization system was submitted on April 17, 2008 and was approved on May 8, 2008.

Revision J to the Erosion and Sediment Control Plan for an increase in disturbed land (additional borrow area) was submitted on October 28, 2008 and was approved on December 17, 2008.

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.

Mayo

The SO_2 scrubber at Mayo has been completed and began operation in early April, 2009. The bioreactor was placed into service in June, 2009. The remaining construction activities at Mayo for 2009 involve resolution of project punch-list items.

Roxboro

During 2009, the remaining construction activities at Roxboro involve final grading, paving and roadwork, resolution of project punch-list items, and additional construction related to the waste water treatment settling and flush ponds.

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.

The following permit applications and permit approvals are anticipated for 2009:

Roxboro Plant

Authorization to Construct

A request for addendum for the Authorization to Construct for repairs to the gypsum settling pond and flush pond for the waste water treatment system was submitted on January 12, 2009. Agency approval was obtained on May 15, 2009.

A request for Authorization to Construct for an additional settling pond for the waste water treatment system was submitted on March 11, 2009. Agency approval was obtained on June 15, 2009.

Erosion and Sedimentation Control Plan

Additional plan revisions may be necessary as construction plans are further developed.

Mayo Plant

Air Permit

A renewal application for the Title V Air Permit was submitted on November 30, 2007. This application contained an update to include NSPS requirements for the emergency quench water pump. Agency approval for the quench water pump was obtained on May 27, 2009.

A permit application submitted for changes to the air permit on January 15, 2009 included revisions to the limestone silo control device arrangement and installation of a dry sorbent injection system for SO_3 control. Agency approval was obtained on May 27, 2009.

NPDES Permit

A revision to the NPDES permit to include limestone and gypsum truck traffic in support of scrubber operation was requested on February 11, 2009 with approval expected in the third quarter 2009.

Authorization to Construct

A request for an addendum to the Authorization to Construct for the waste water treatment system was submitted on September 12, 2008, which revises the design of the HDPE liner and base of the settling pond. Approval of this request was issued on February 23, 2009.

Erosion and Sedimentation Control Plan

Plan revisions may be necessary as construction plans are further developed.

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

Performance testing of the scrubbers on Roxboro Units 3 and 4 was completed in 2008. The testing confirmed that each scrubber achieved its performance guarantee of 97% SO_2 removal efficiency.

Testing of the scrubber at Mayo is planned for later this year.

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

The affected coal-fired PEC units have achieved a 59% reduction in NOx and a 56% reduction in SO_2 since 2002. The total calendar year 2008 emissions from the affected coal-fired Progress Energy Carolinas units are:

NOx 24,190 tons
SO_2 94,221 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 2008, 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

July 31, 2009

On June 20, 2002, Governor Easley signed into law SB1078, which caps emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) from utility owned coal-fired power plants located in North Carolina. Under the law, G.S. § 143-215.107D, PEC's annual NOx emissions must not exceed 25,000 tons beginning in 2007 and annual SO_2 emissions must not exceed 100,000 tons beginning in 2009 and 50,000 tons beginning in 2013. These caps represent a 56% reduction in NOx emissions from 2001 levels and a 74% reduction in SO_2 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 NOx emissions controls on its coal-fired power plants since 1995 in order to comply with Title IV of the Clean Air Act and the NOx SIP Call rule adopted by the Environmental Management Commission (EMC). Substantial NOx emissions reductions have been achieved (24,383 tons of NOx in 2007 compared with 112,000 tons in 1997), and compliance with the Clean Smokestacks Act's 25,000 ton cap was achieved in calendar year 2007. This target was achieved with a mix of combustion controls (which minimize the formation of NOx), such as low-NOx burners and over-fire air technologies, and post-combustion controls (which reduce NOx produced during the combustion of fossil fuel to molecular nitrogen), such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies.

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

Sulfur Dioxide Emissions Control Plan

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

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

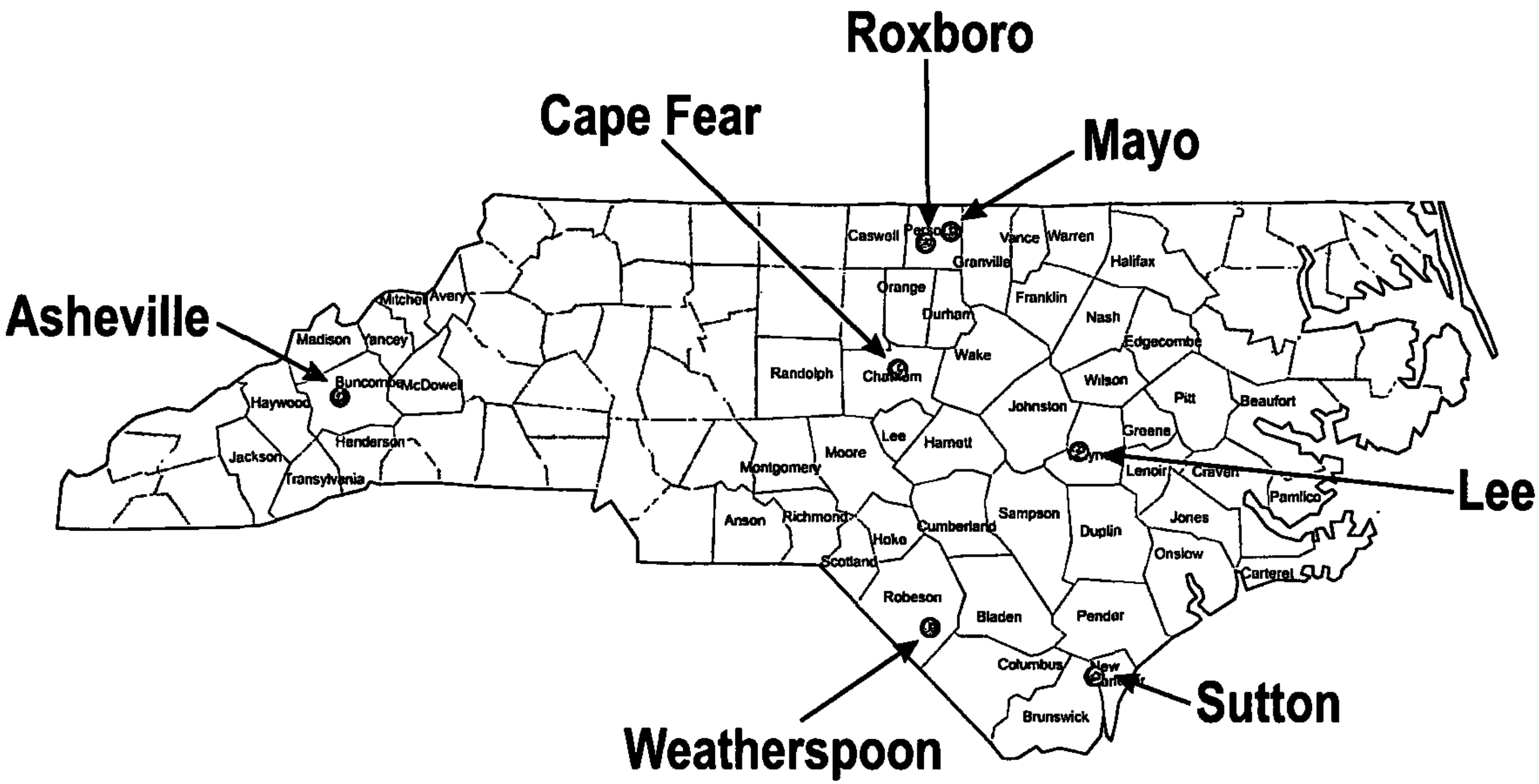
A contract has been executed with a gypsum product end-user that will construct a facility near the Roxboro Plant to use the synthetic gypsum produced by the Roxboro and Mayo Plants for the manufacture of drywall products. PEC also has entered into an agreement that enables PEC to sell synthetic gypsum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

We regularly review and refine our compliance strategy, weighing a number of factors such as system load projections, new natural gas supply, natural gas-fired generation options, coal unit retirements, updated load and energy forecasts, updated fuel costs, updated capital and operating costs, and federal and state environmental legislative and regulatory developments. As a result of recent resource planning studies taking all of these drivers into account, PEC has determined that retirement of a coal-fired plant and replacement of that plant with a combined-cycle natural gas-fired unit represents a cost-effective resource plan for our system. Accomplishing this retirement and replacement by 2013 eliminates the need for a sulfur dioxide scrubber on Sutton Unit 3 in order to comply with the 2013 Clean Smokestacks Act limits.

With this plan, additional controls are not needed at Sutton 3 to meet the 2013 Clean Smokestacks Act limits, therefore that unit is no longer shown in Appendix B and the compliance costs have been reduced accordingly.

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

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



Attachment 2: PEC's 2009 NOx Control Plan for North Carolina Coal-fired Units

Unit	MW Rating	Control Technology	Operation Date[1]
Asheville 1	191	LNB/AEFLGR/**SCR**	2007
Asheville 2	185	LNB/OFA/SCR	
Cape Fear 5	144	ROFA/ROTAMIX	
Cape Fear 6	172	ROFA/ROTAMIX	
Lee 1	74	WIR	
Lee 2	77	**LNB**	2006
Lee 3	246	LNB/**ROTAMIX**	2007
Mayo 1	742	LNB/OFA/SCR	
Roxboro 1	369	LNB/OFA/SCR	
Roxboro 2	662	TFS2000/SCR	
Roxboro 3	695	LNB/OFA/SCR	
Roxboro 4	698	LNB/OFA/SCR	
Sutton 1	93	SAS	
Sutton 2	104	**LNB**	2006
Sutton 3	403	LNB/ROFA/ROTAMIX	
Weatherspoon 1	48		
Weatherspoon 2	49		
Weatherspoon 3	75	WIR	
Total	5,027		

AEFLGR – Amine-Enhanced Flue Lean Gas Reburn
LNB = Low NOx Burner
SNCR = Selective Non-Catalytic Reduction
OFA = Ovcrfire 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).

Attachment 3: PEC's 2009 SO_2 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	191	Scrubber	2005	1,003	316
Asheville 2	185	Scrubber	2006	770	286
Cape Fear 5	144			4,829	5,910
Cape Fear 6	172			6,705	6,186
Lee 1	74	Retirement	2013	2,086	0
Lee 2	77	Retirement	2013	2,325	0
Lee 3	246	Retirement	2013	8,369	0
Mayo 1	742	Scrubber	2009	5,232	1,969
Roxboro 1	369	Scrubber	2008	1,341	884
Roxboro 2	662	Scrubber	2007	2,687	1,203
Roxboro 3	695	Scrubber	2008	2,716	1,333
Roxboro 4	698	Scrubber	2007	3,120	1,351
Sutton 1	93			2,428	3,417
Sutton 2	104			2,428	3,992
Sutton 3	403			12,251	13,920
Weatherspoon 1	48			851	1,177
Weatherspoon 2	49			851	1,310
Weatherspoon 3	75			1,947	2,441
Total	5,027			61,938	45,695

[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 Actual Costs Through 2008 and Projected Costs Through 2013

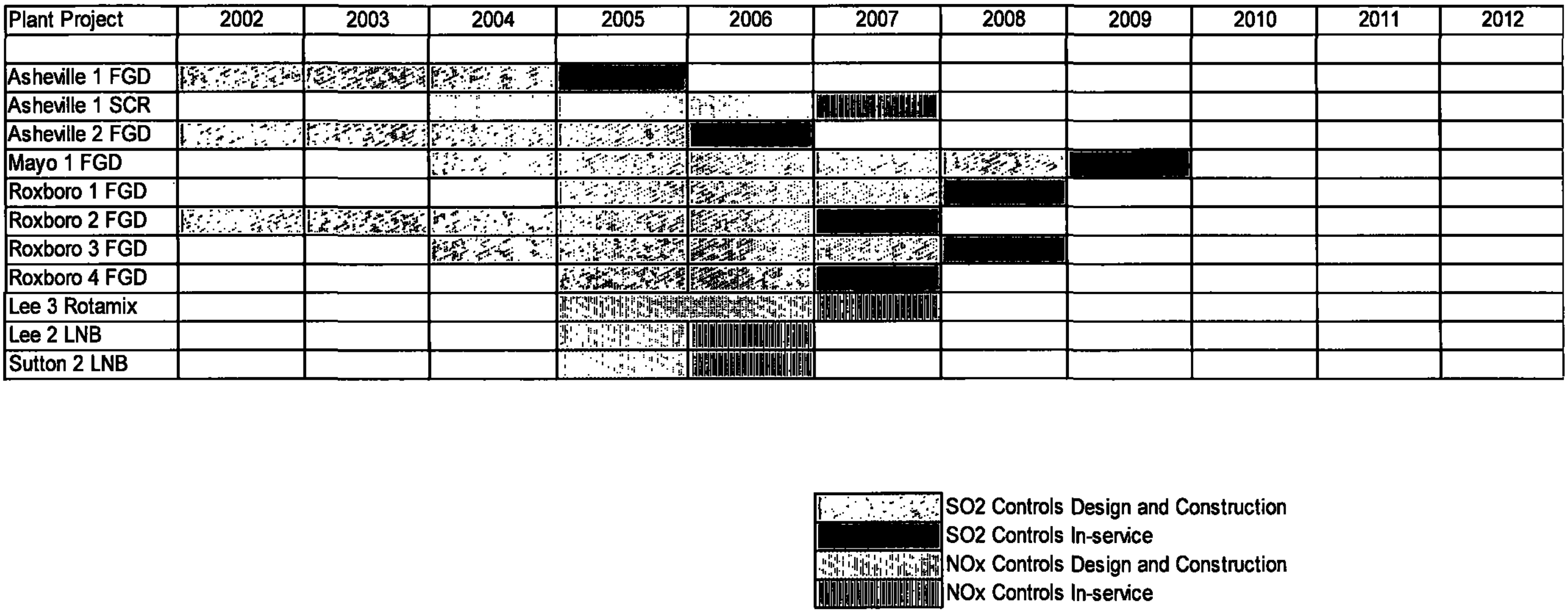
PGN Financial View Cost Net of Power Agency Reimbursement (in thousands)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Asheville 1 FGD	$ 100	$ 9,652	$ 33,574	$ 35,769	$ 3,930	-$ 1,850	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 81,175**
Asheville 1 SCR	$ 0	$ 0	$ 688	$ 1,423	$ 14,608	$ 11,942	-$ 262	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 28,400**
Asheville 2 FGD	$ 100	$ 7,742	$ 28,390	$ 24,238	$ 11,701	-$ 1,543	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 70,629**
Asheville FGD Common	$ 467	$ 0	$ 0	$ 0	$ 0	-$ 479	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	**-$ 12**
Mayo 1 FGD	$ 187	$ 0	$ 276	$ 644	$ 22,794	$ 104,886	$ 67,703	$ 24,684	$ 2,596	$ 0	$ 0	$ 0	**$ 223,769**
Roxboro FGD Common	-$ 15	$ 5,560	$ 10,030	$ 51,717	$ 72,934	$ 36,491	-$ 1,360	$ 2,524	$ 0	$ 4,000	$ 0	$ 0	**$ 181,881**
Roxboro 1 FGD	$ 434	$ 0	$ 0	$ 3,135	$ 12,164	$ 32,841	$ 24,905	$ 1,387	$ 0	$ 0	$ 0	$ 0	**$ 74,866**
Roxboro 2 FGD	$ 120	$ 3,574	$ 6,848	$ 30,782	$ 46,014	$ 18,975	-$ 357	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 105,955**
Roxboro 3 FGD	$ 0	$ 0	$ 244	$ 10,628	$ 36,661	$ 49,985	$ 9,006	$ 293	$ 0	$ 0	$ 0	$ 0	**$ 106,817**
Roxboro 4 FGD	$ 0	$ 0	$ 0	$ 9,074	$ 28,550	$ 57,610	$ 1,876	$ 125	$ 0	$ 0	$ 0	$ 0	**$ 97,235**
Lee 3 Rotamix	$ 0	$ 0	$ 0	$ 198	$ 6,424	$ 600	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 7,222**
Lee 2 LNB	$ 0	$ 0	$ 133	$ 273	$ 1,886	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 2,292**
Sutton 2 LNB	$ 0	$ 0	$ 0	$ 236	$ 1,900	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 2,136**
Total without Waste Water	**$ 1,393**	**$ 26,527**	**$ 80,184**	**$ 168,118**	**$ 259,566**	**$ 309,456**	**$ 101,510**	**$ 29,014**	**$ 2,596**	**$ 4,000**	**$ 0**	**$ 0**	**$ 982,364**
Asheville WWT	$ 0	$ 0	$ 0	$ 12,365	$ 1,289	-$ 306	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 13,348**
Mayo WWT	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,042	$ 6,604	$ 9,814	$ 719	$ 0	$ 0	$ 0	**$ 21,179**
Roxboro WWT	$ 0	$ 0	$ 0	$ 791	$ 11,965	$ 16,932	$ 5,127	$ 8,532	$ 5,317	$ 2,800	$ 0	$ 0	**$ 51,464**
Total Waste Water Treatment	**$ 0**	**$ 0**	**$ 0**	**$ 13,156**	**$ 13,253**	**$ 20,668**	**$ 11,732**	**$ 18,346**	**$ 6,036**	**$ 2,800**	**$ 0**	**$ 0**	**$ 85,991**
Total NC Smokestacks	**$ 1,393**	**$ 26,527**	**$ 80,184**	**$ 181,273**	**$ 272,819**	**$ 330,124**	**$ 113,242**	**$ 47,360**	**$ 8,632**	**$ 6,800**	**$ 0**	**$ 0**	**$ 1,068,355**
Total Estimated AFUDC							**$ 6,148**	**$ 2,780**	**$ 118**	**$ 0**	**$ 0**	**$ 0**	**$ 9,047**

Notes:

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

Appendix C
PEC's Clean Smokestacks Act Compliance Plan



Attachment 2

The economic analysis of the Wayne County 3x1 CC project compares the cost of building a new 3x1 combined cycle unit to the cost of continuing to operate the Lee 1, 2, and 3 coal units, including the cost of potential environmental modifications that could be required due to proposed emission regulations.

The 3x1 combined cycle unit proposed for Wayne County is approximately 950 MW. The total capacity of the existing coal units at Lee is approximately 400 MW. The approximate 550 MW difference in capacity may result in a change in the resource plan, or as stated in the Application, it may be used to replace other existing uncontrolled coal units or displace coal-fired generation on the PEC system. For simplicity, the additional generation has been assumed to meet future load growth and replace planned unit additions in the resource plan in this analysis.

The 550 MW of additional capacity provided by a 3X1 combined cycle unit in 2013 would delay CTs required to meet load in2015 and 2016 to 2017 and 2018. Since the additional 550 MW capacity in 2013 is combined cycle, this capacity would also essentially replace and eliminate the need for the 2017 combined cycle unit. However, some additional capacity is needed in 2018, so a CT was added to the resource plan. The changes made to the resource plan are summarized in the table below.

	Base Plan	Plan with Wayne County CC
2013		Retire Lee 1-3 coal Wayne County 3x1 CC Duct-Fired
2014		
2015	CT 190 Frame (Oil)	
2016	CT 190 Frame (Oil)	
2017	CC 2x1 Duct-Fired	CT 190 Frame (Oil)
2018		2 CT 190 Frame (Oil)

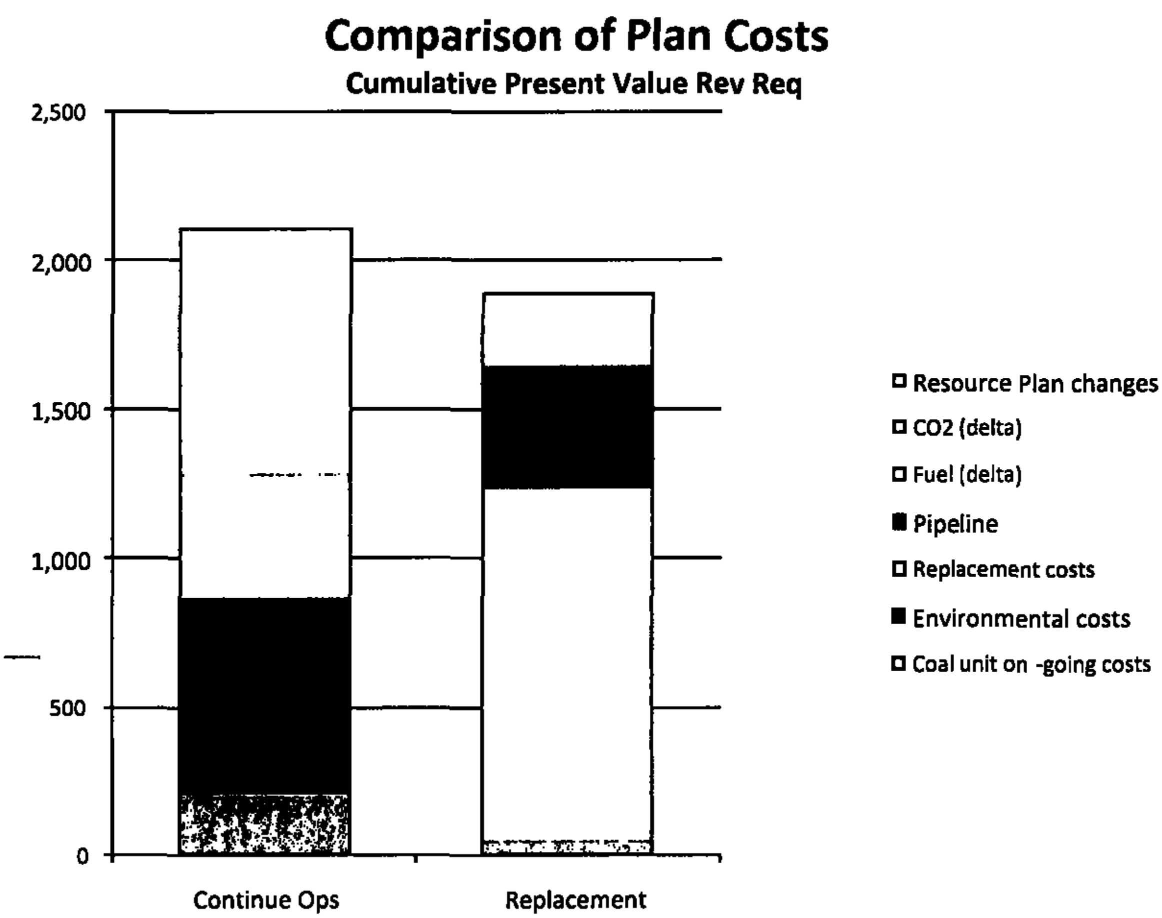
If the Lee coal units are not retired, they could be required to comply with new emission regulations as early as 2015. These new regulations could require SO_2 and NOx controls on all three units. Continued operation of the Lee coal units will also require a new monofill for coal combustion products (CCP) at Lee. Retiring the coal units and replacing them with the 3x1 combined cycle will eliminate the need for these controls, saving over $500 million in environmental compliance-related capital expenditures, as shown in the table below.

Project	In-Service	Total Capital ($M)
Lee 1&2 DFGD	1/1/2014	152.9
Lee 1&2 SNCR	1/1/2015	14.0
Lee 3 DFGD	1/1/2014	212.9
Lee 3 SCR	1/1/2014	116.3
Lee CCP (initial)	6/1/2013	20.3
Total		516.4

Replacement of these coal units with combined cycle capacity will also reduce CO_2 emissions. This will be advantageous if some form of CO_2 regulation, imposed either by federal legislation or regulation by the U.S. Environmental Protection Agency, is enacted.

Retiring the coal units will also avoid on-going capital and O&M expenditures for the units. These costs are estimated to sum to over $80 million (nominal dollars) in capital and $500 million (nominal dollars) in O&M through the study period. Of course, these cost savings are offset by on-going O&M and capital expenditures for the new combined cycle unit.

The economic analysis of the Wayne County 3x1 combined cycle unit was performed in terms of cumulative present value of revenue requirements (CPVRR). The stacked bar chart below shows the cost of replacing the Lee Plant with the 3x1 combined cycle unit is less costly than continuing the operation of Lee coal units assuming future environmental regulations including CO_2. The total savings associated with replacing is more than $213 million (CPVRR, 2009 dollars). The components of cost for each of the alternatives are represented by the different segments of the bars.

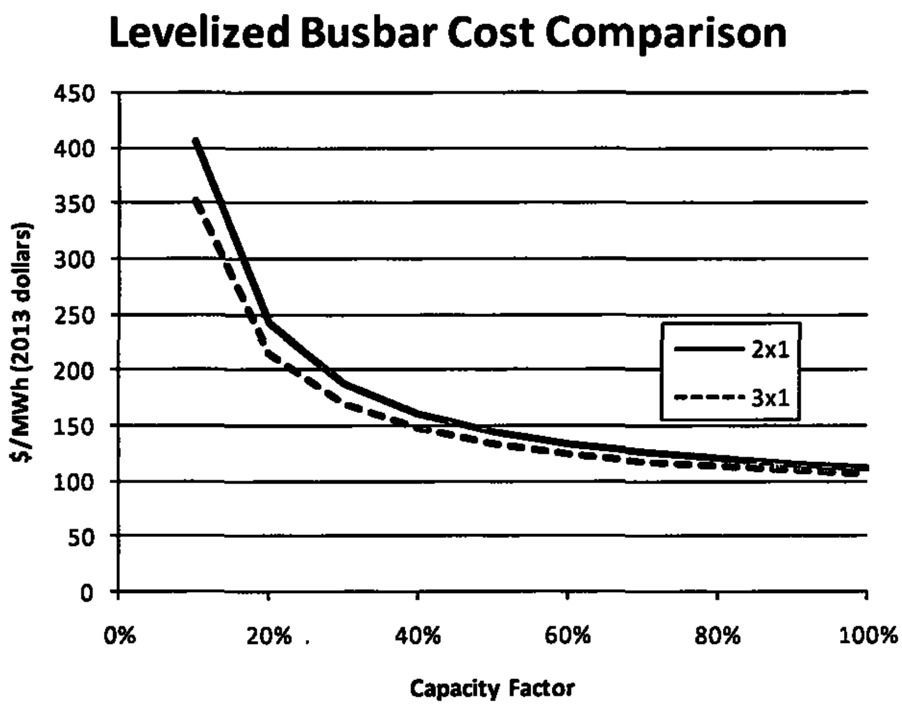


For the Continued Operations case, the cost components are the on-going O&M and capital costs to operate and maintain the Lee coal units (the bottom blue segment); the cost of adding emission controls to the units (including O&M and consumables costs), represented by the red segment; the cost of CO_2 emissions, represented by the orange segment; and, the costs associated with the difference in the resource plans. The CO_2 emission difference considered here is the difference in CO_2 emissions between the case with replacing Lee compared to the case with Lee continuing operations. The changes in the resource plan (as discussed above) are typically viewed as savings associated with the Replacing case; however, to make the bar chart easier to read, they are represented here as costs to the Continued Operations case.

For the Replacing case, the components are the on-going O&M and capital costs of the coal units until they are retired at the end of 2012; the O&M and capital costs of the new 3x1 combined cycle unit, represented by the green segment; the gas pipeline reservation costs, represented by the purple segment; and, the change in total system fuel and purchased power costs from the Continued Operations case, represented by the aqua segment.

Attachment 3

Levelized Cost Comparison of 2x1 CC v. 3x1 CC



Attachment 4
Redacted

(Unredacted provided in sealed envelope)

A. Wayne County CC Project Cost Estimate

Wayne County 3x1 Combined Cycle
Preliminary Cost Estimate (Nominal $$ in Thousands)

GENERATION FACILITIES	
Plant Equipment & Spares	[redacted]
Engineering, Procurement & Construction	[redacted]
Project Management & Owner's costs	[redacted]
Allowance for Funds Used During Construction	[redacted]
TOTAL GENERATION FACILITIES COST	[redacted]
PROPERTY ACQUISITION	[redacted]
TRANSMISSION FACILITIES	
Transmission Facilities	[redacted]
Allowance for Funds Used During Construction	[redacted]
TOTAL TRANSMISSION FACILITIES	[redacted]
TOTAL PROJECT COSTS	[redacted]

B. Wayne County CC Project Schedule

Start of Construction	September 1, 2010
Start of Testing	September 1, 2012
Commercial Operation	January 1, 2013

C. Wayne County CC Estimated Operational Costs

Estimated Operational Costs (Nominal $$ in Millions)						
Accounting Operational Cost	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
LTSA O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Outage BOP & STG O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total O&M expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LTSA Cap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LTSA Outage Cap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Inventory increase	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BOP Capital Spares	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Inventory Increase	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

D. Wayne County CC Projected Operating Data

Unfired Full Load Heat Rate (Btu/kWh)	[redacted]	
Fuel Cost ($/MMBtu)	[redacted]	(2013$)
Energy Cost ($/MWh)	[redacted]	(2013$)
Gas Pipeline Reservation (M$/Yr)	[redacted]	(Fixed)
Capacity Factor (%)	[redacted]	
Book Life (Years)	[redacted]	

Assumptions relative to current costs and forecasts vary and are subject to change.

Progress Energy Carolinas, Inc.'s Plan to Retire 550 MWs of Coal Generation Without SO_2 Controls filed in Docket No. E-2, Sub 960 on December 1, 2009

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Progress Energy

December 1, 2009

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

RE: Docket No. E-2, Sub 960

Dear Ms. Vance:

Enclosed for filing in the above-referenced docket are the original and 30 copies of Progress Energy Carolinas, Inc.'s Plan to Retire 550 MWs of Coal Units Without SO_2 Controls.

Sincerely,

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

LSA:mhm

Attachment

STAREG787

(Lo3)
2 AA
Dennis
Kirk
Watson
Hoover
Sessoms
Kite
Ericson
Jones
Hilburn
Bowler
Legal 3
Acct 3
EC/Res 2
Elect 3

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

OFFICIAL COPY

VERIFICATION

STATE OF NORTH CAROLINA)
) **DOCKET NO. E-2, SUB 960**
COUNTY OF WAKE)

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

That he is Glen Snider, Manager, Resource Planning-TOP for Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; he has the authority to verify the foregoing Progress Energy Carolinas, Inc.'s Plan to Retire 550 MWs of Coal Generation Without Sulfur Dioxide Controls; that he has read said Plan and knows the contents thereof are true and correct to the best of his knowledge and beliefs.

Glen Snider
Manager, Resource Planning-TOP
Progress Energy Carolinas, Inc.

Subscribed and sworn to me
this 1st day of December, 2009.

Marsha H. Manning

MARSHA H MANNING
NOTARY PUBLIC
WAKE COUNTY, NC
My Commission Expires 10-3-2014

STAREG789

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Clerk's Office
N.C. Utilities Commission

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 960

Application for Certificate of Public Convenience and Necessity to Construct a 950 MW Combined Cycle Natural Gas Fueled Electric Generation Facility in Wayne Co. and Motion for Waiver of Rule R-8-61	))))))	**PROGRESS ENERGY CAROLINAS, INC.'S PLAN TO RETIRE 550 MWS OF COAL GENERATION WITHOUT SO_2 CONTROLS**

Pursuant to the North Carolina Utilities Commission's (the Commission) order issued October 22, 2009, Progress Energy Carolinas, Inc. (PEC) submits for Commission approval its plan to retire approximately 550 MWs of coal fired generating facilities that do not have flue gas desulfurization equipment (scrubbers).

PEC owns and operates a total of 1485 MWs of coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities are located across PEC's service territory at its Lee, Sutton, Cape Fear, and Weatherspoon Plant sites (see Appendix 1).[1] As more thoroughly explained below, in order for PEC to continue operating these units PEC will, in all probability, be required to make significant investments in each unit to install equipment to control emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), mercury (Hg), and greenhouse

[1] PEC is continuing to evaluate options for its 174 MW Robinson Coal Plant located in Darlington, South Carolina.

gases (GHGs). In addition to installing additional controls to limit their airborne emissions, PEC will have to address foreseeable regulatory constraints associated with operating these environmental controls, such as their wastewater, as well as the by-products of combustion of coal, in particular bottom ash, fly ash, and gypsum. These environmental regulatory requirements and the order in which they are expected to be encountered are generally as follows:

Mercury (Hg) and other hazardous air pollutants (HAPs)

In 2006, North Carolina adopted mercury emission regulations (15A NCAC 02D.02500) (N.C. Mercury Rules). The N.C. Mercury Rules establish mercury limits (15A NCAC 02D.2511), allocate emission allowances (15A NCAC 02D.2503) and require all coal-fired units to have mercury-control technology installed no later than December 31, 2017. The N.C. Mercury Rules are, in some respects, more stringent than the federal Clean Air Mercury Rule (CAMR) promulgated by the United States Environmental Protection Agency (EPA).

On February 8, 2008, the Court of Appeals for the District of Columbia Circuit vacated CAMR. The vacatur eliminated all mercury allowance trading and allocations under CAMR. However, the decision did not directly affect the N.C. Mercury Rules which remain in effect unless changed by state action. The N.C. Mercury Rules require PEC to develop an emission control plan for each operating unit by January 1, 2013, that identifies the schedule for installation and operation of mercury controls. To meet this requirement, PEC will have to invest significant capital in control technologies or retire the coal unit. EPA is currently developing Maximum Achievable Control Technology (MACT) standards for mercury and other hazardous air pollutants emitted by steam generators that likely will result in further emission-reduction requirements. EPA is scheduled to propose the MACT in March 2011 with a final version expected in November 2011. PEC expects the mercury MACT and HAP compliance requirements to be in effect by 2014 or 2015.

Sulfur dioxide (SO_2)

Both the North Carolina Clean Smokestacks Act and the federal Clean Air Interstate Rule ("CAIR") require reductions in SO_2 emissions. By January 1, 2013, PEC is required by the Clean Smokestacks Act to reduce its annual North Carolina emissions of SO_2 from its coal fired plants to 50,000 tons or fewer. [G.S. Section 143-215.107D(e)(2)]. PEC will achieve the required reduction in 2013 by retiring the Lee Plant.

North Carolina adopted its own rules implementing CAIR, which were codified at 15A NCAC 02D .2401 et seq. (N.C. CAIR). N.C. CAIR provides for an allowance trading system under which an entity subject to CAIR could either reduce its emissions to the required limit, purchase sufficient allowances to comply with the rule's requirements, or undertake a combination of both. CAIR would require further system-wide SO_2 emission reductions by 2015 or the purchase of allowances.

In July 2008, the Court of Appeals for the District of Columbia Circuit vacated federal CAIR. In substance, the Court found that the allowance trading system, which was an integral and essential part of CAIR, was inconsistent with the requirements of the federal Clean Air Act. In response to a petition by EPA, in December 2008, the Court modified its earlier opinion to remand the case to EPA without vacatur, in order to allow EPA to conduct further proceedings consistent with that prior opinion. EPA has noted that the withdrawal of the vacatur "means that CAIR....remain[s] in effect while EPA develops a replacement rule consistent with the [earlier] opinion." 74 Fed. Reg. 56722 (Nov. 3. 2009). In the interim, the N.C. CAIR remains in effect.

The revised federal CAIR will likely require point-source-specific controls, rather than allowing an allowance trading compliance process. As a result, PEC's Weatherspoon, Cape Fear and Sutton plants will either have to be retired, or PEC will have to make significant investments in control technology for these plants. PEC anticipates the revised CAIR will require additional SO_2 reductions by 2017.

Carbon Dioxide (CO_2)

In response to the 2008 opinion of the U.S. Supreme Court in Massachusetts v. EPA, (549 U.S. 497, 127 S.Ct. 1438 (2007)), EPA issued a proposed "endangerment finding," which, when issued in final form, will formally declare that CO_2 and five other greenhouse gases are pollutants that threaten public health and welfare. This finding will give EPA the authority to regulate CO_2 under the Clean Air Act. The endangerment finding has been sent to the White House Office of Management and Budget for final review.

On October 30, 2009, EPA issued a final rule requiring reporting of GHG emissions from sources emitting more than 25,000 metric tons of CO_2 per year. This rule goes into effect on December 29, 2009.

EPA has also issued a proposed rule applicable to stationary sources, including power plants that emit more than 25,000 tons per year of GHGs. The proposed rule links GHG regulation under Title V (operating permit program) and the Prevention of Significant Deterioration (PSD) portion of New Source Review (NSR). Under Title V, existing permits would not be modified to incorporate the GHG requirements until permit renewal. New or modified facilities that trigger PSD permitting requirements would need to apply for a revised permit that incorporates best available control technology (BACT) and energy efficiency measures to minimize GHG emissions. BACT for GHG has not been determined.

Concurrently, Congress is considering legislation to regulate GHGs. H.R.2454, the American Clean Energy and Security Act of 2009 (ACES), also known as the Waxman-Markey bill, was approved by the House of Representatives on June 26, 2009. In the Senate, S. 1733, the Clean Energy Jobs and American Power Act, also known as the Kerry-Boxer bill, has been introduced, and approved by a key committee. Both bills incorporate a three-pronged approach that proposes to (1) reduce national GHGs from industrial sources over a 38-year period, (2) establish a market-based system for trading emission allowances, and (3) establish a GHG emissions reporting mechanism. Under both bills, actual source emissions are not restricted, but the ability to obtain allowances or offsets will be limited over the course of time as the national emissions caps are reduced. Many important differences exist between the House and Senate bills, including the EPA's authority to regulate GHGs. In contrast to the House bill, the Senate bill retains most of EPA's authority to regulate GHGs under the Clean Air Act.

In the absence of Congressional adoption of a statute to address CO_2 emissions, EPA regulatory efforts are expected to continue with a final determination on endangerment to be issued shortly. This step will provide a basis for regulating CO_2 under the existing provisions of the Clean Air Act and the possibility of requirements imposed in future and current air emission permits. It appears likely that there will be federal regulation of CO_2 emissions as well as other GHG emissions and precursors.

Finally, two recently issued federal appellate court decisions reinforce the assumption that regulation of GHGs will occur in the near future. On September

22, 2009, the U.S. Court of Appeals for the Second Circuit in Connecticut v. AEP et al., (582 F.3rd 309 (2009)) reinstated an action dismissed by a federal district court and held that those with standing can pursue claims of harm from CO_2 emissions if facts show that the injuries are "fairly traceable" to the defendant's CO_2 emissions and account for a significant percent of U.S. CO_2 emissions. The court held that the case could proceed on a "public nuisance" theory since there is no statutory framework that addresses the remedy requested by the plaintiffs. On October 16, 2009, the U.S. Court of Appeals for the Fifth Circuit in Comer v. Murphy Oil, USA, et al. (2009 WL 3321493 (5th Cir. 2009); Slip Op. No. 07-60756 (Oct. 16, 2009)) held that private parties have a right to pursue federal and state common law public and private nuisance, trespass and negligence claims against a wide range of energy companies alleging harm resulting from emissions of GHGs. Given that these are state law claims, federal regulation of GHGs may not necessarily extinguish the right to pursue all of the claims asserted.

All of the above indicate that GHGs, in particular carbon dioxide, likely will be subject to some form of regulation resulting in required emission reductions or purchases of allowances as soon as 2012.

Coal Combustion Products (CCPs)

EPA is currently considering re-characterizing the nature of and regulation of coal combustion products (bottom ash, fly ash and related materials, hereinafter

CCPs) in response to TVA's Kingston Plant ash pond impoundment failure. Speculation is focusing on EPA's regulation of CCPs as a hazardous waste. A narrow usage exclusion may be possible where the finished product of CCP is fully encapsulated. Existing uses that involve land application or unconfined uses may be prohibited. If EPA characterizes CCPs as a hazardous waste or otherwise increases the regulatory requirements applicable to CCPs, the handling, storage and disposal of this material will result in significantly increased costs of operation, and more sophisticated handling equipment and disposal requirements. Classification of power plant CCP operations as activities that produce hazardous wastes as defined by the Resource Conversation and Recovery Act (RCRA) would trigger a number of additional regulatory requirements as well as potential liability associated with closure of impoundments, leachate management and site remediation. Phase out of surface impoundments is under consideration by EPA.

NOx, SO_2 & Particulate Matter

The revised federal CAIR is expected to require NOx and SO_2 reductions, which may also be driven by reasonably available control technology (RACT) limits necessary to achieve future ambient air-quality standards for ozone. In addition, revised and more stringent ambient air-quality standards for particulate matter are expected to be issued in 2011 which might result in additional reduction requirements for that pollutant and its precursors (SO_2, NOx).

In addition, EPA proposed a new 1-hour SO_2 ambient air quality standard in November, 2009. It is significantly more stringent than the current annual and 24-hour SO_2 ambient air quality standards. EPA is expected to finalize this revision in 2010.

It is against this backdrop that PEC must evaluate the future of its coal-fired generating units that do not have scrubbers. Scrubbers may allow PEC to comply with additional mercury and SO_2 emissions reduction requirements. However, they provide no relief with regard to NOx, GHG emissions and CCP issues

FACILITY PLAN OVERVIEW

Lee Plant

As explained by PEC in its application for a certificate of public convenience and necessity filed in Docket No. E-2, Sub 960, which is incorporated herein by reference, PEC has determined that the most cost effective means of complying with the North Carolina Clean Smokestacks Act, in particular the requirement to reduce SO_2 emissions to 50,000 tons in 2013 and to proactively address the environmental requirements described above, is to retire its 400 MW Lee Plant facility and replace it with natural gas-fired generation. By order issued October 22, 2009, the Commission granted PEC's application for a certificate to build a 950-MW natural gas-fired combined-cycle facility to replace the 400 MW

Lee Plant. The incremental 550 MWs of generating capacity will be available to serve future load growth or replace the Weatherspoon and/or Cape Fear plants.

Sutton Plant

PEC's Sutton coal-fired units located near Wilmington, N.C., is a 600 MW facility. Due to specific operating procedures for PEC's Brunswick Nuclear Plant located in Southport, N.C., and due to local voltage support requirements of the greater Wilmington area, PEC must maintain approximately that amount of generation capacity at that location. As a result, PEC cannot use any of the incremental 550 MWs of gas-fired generation to be built in Wayne County to replace the generation at the Sutton Plant. Thus, PEC must either invest significant capital in control technologies or construct new gas-fired generation at this location. The questions then are which option is most cost-effective, and, if retirement is the prudent course of action, when should the Sutton coal units be retired and replaced with a new natural gas-fired facility. Based on the following, PEC has concluded that this plant should be retired and replaced with a new gas-fired generation facility in 2014.

Environmental Considerations

The current ash pond at the Sutton Plant will reach full capacity on or before 2014. As mentioned earlier, PEC anticipates mercury emission-reduction requirements, SO_2 and NOx emission-reduction requirements and GHG regulation in the 2015-2017 timeframe. As a result, the 2014 date will allow PEC to avoid significant investment in environmental controls on the existing units, avoid additional coal ash-removal costs caused by continued operation, and reduce CO_2 compliance costs.

Market and Procurement Considerations

PEC's recent experience in bidding the major equipment, engineering, procurement and construction contracts for the Wayne County natural gas-fired combined-cycle facility demonstrates that the costs of all such equipment and services are at low levels due to the state of the economy. It is PEC's belief that these costs are unlikely to decrease further and taking advantage of these depressed prices now is the prudent course of action before they begin to increase. From a construction management perspective, a 2013 commercial operation date for the Wayne County facility followed by a 2014 commercial operation date for a Sutton combined cycle facility will allow PEC to realize economies of scale by combining the projects in the competitive bidding procurement process.

PEC's cost/benefit analysis comparing continued operation with retirement and replacement with gas-fired combined-cycle generation demonstrates retirement and replacement is the most prudent course of action. As a result, PEC anticipates filing for a certificate of public convenience and necessity to construct a 600 MW

2x1 natural gas-fired combined-cycle generator at the Sutton Plant location sometime within the next two months.

Cape Fear and Weatherspoon Plants

PEC's Cape Fear and Weatherspoon coal-fired generating facilities consist of five units with a total generation capacity of approximately 500 MW. These plants face the same environmental compliance issues as the Sutton coal units.

Continued operation will require the construction of new ash ponds at both facilities or conversion to dry ash storage. They will also have to meet anticipated mercury emission-reduction requirements, SO_2 and NOx emission-reduction requirements and GHG regulation in the 2015-2017 timeframe. As a result, PEC must either invest significant capital in control technologies at these facilities or retire them. Applying the same analyses used to determine that retiring and replacing the Sutton coal units is the most prudent course of action, PEC has determined that these plants also should be retired. The question then is when these plants should be retired. Unlike the Sutton Plant, the replacement generation for these plants does not have to be located at these plant sites. Therefore, the incremental 550 MW of natural gas-fired combined-cycle generation to be built in Wayne County can be used to replace these units. As a result, these plants can be retired anytime after the new Wayne County generation is placed in service.

However, these sites have valuable infrastructure in place, including but not limited to, existing permits, cooling ponds, cooling towers, generation substations and skilled labor, that can be used for future electric generation purposes. In addition to traditional infrastructure, the facilities are also located in proximity to renewable fuel sources, such as woody biomass. Given PEC's requirement to comply with North Carolina's renewable mandates under G.S. § 62-133.8 and the potential for even more aggressive federal renewable requirements contained in Congressional proposals, PEC is conducting engineering analysis to ascertain the viability of converting a portion (*50-100 MW*) of these facilities to renewable resources. At this point, these studies are not complete, and no formal decision has been reached. Factors affecting this decision include final study results, relative cost compared to renewable purchase alternatives, and ultimate renewable mandates that evolve from federal legislation. In addition, PEC continues to view these sites as potential locations for future natural gas fired generation, if planning conditions warrant.

Other factors to be considered include the impact of retirement of these facilities on the local communities in close proximity to these plants, the employee impacts, and scheduling issues.

With respect to the timing of the retirements and potential conversions of a portion of these facilities to renewable resources, PEC estimates 2013 to 2017 to be the most likely time period.

SUMMARY

PEC anticipates retiring all of its coal-fired generating facilities in North Carolina that do not have scrubbers no later than December 31, 2017.[2] The Weatherspoon and Cape Fear Plants will likely retain the balance of the site infrastructure in some form beyond this period. As previously stated, these sites have inherent value in terms of land, water, transmission, permits, skilled labor, etc. that provide siting options for future resources within PEC's longer term balanced solution strategy as presented in the annual integrated resource plan.

PEC intends to move fairly quickly to retire and replace the Sutton Plant. The retirement of the Weatherspoon and Cape Fear coal operations depends upon the results of the studies evaluating the cost-effectiveness of converting a portion of these plants to run on renewable fuel, most probably biomass and the impacts on the local communities and the plant employees.

[2] It must be recognized that these retirement plans are based upon certain assumptions regarding anticipated environmental requirements. Should these assumptions prove to be wrong or change, PEC's plans for retiring these plants may also change.

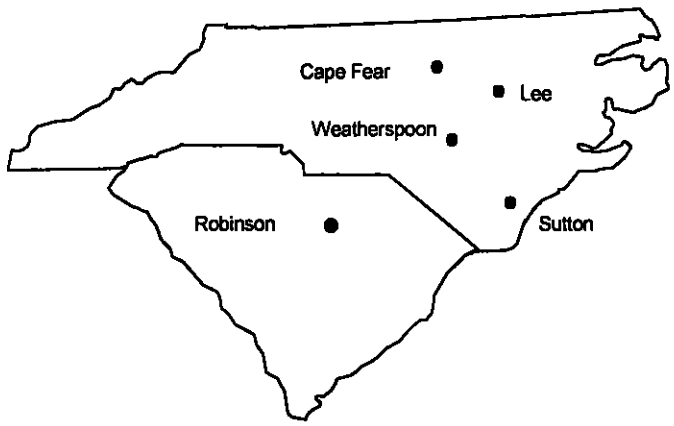
Respectfully submitted this lst day of December, 2009.

PROGRESS ENERGY CAROLINAS, INC.

Len S. Anthony
General Counsel
P. O. Box 1551, PEB 17A4
Raleigh, NC 27602
Telephone: (919) 546-6367
Email: Len.S.Anthony@pgnmail.com

APPENDIX 1

Coal Plants Without Flue Gas Desulfurization



Unit	Capacity	In Service	Unit	Capacity	In Service
Cape Fear 5	144 MW	1956	Sutton 1	93 MW	1954
Cape Fear 6	172 MW	1958	Sutton 2	104 MW	1955
Lee 1	74 MW	1952	Sutton 3	403 MW	1972
Lee 2	77 MW	1951	Weatherspoon 1	48 MW	1949
Lee 3	246 MW	1962	Weatherspoon 2	49 MW	1950
Robinson 1	174 MW	1960	Weatherspoon 3	75 MW	1952

TOTAL SUMMER RATING 1,659 MW

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 960

Application for Certificate of Public Convenience and Necessity to Construct a 950 MW Combined Cycle Natural Gas Fueled Electric Generation Facility in Wayne Co. and Motion for Waiver of Rule R-8-61	)))))	**CERTIFICATE OF SERVICE**

I, Len S. Anthony, hereby certify that Progress Energy, Carolinas, Inc.'s Plan to Retire 550 MWs of Coal Generation Without SO_2 Controls has been served on all parties of record either by hand delivery or by depositing said copy in the United States mail, postage prepaid, addressed as follows this the 1st day of December, 2009:

Antoinette R. Wike, Esq.
Public Staff - N.C. Utilities Commission
Post Office Box 29520
Raleigh, North Carolina 27626-0520

Leonard G. Green
Associate Attorney General
N.C. Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602

Gray Styers
Blanchard, Jenkins, Miller & Styers, P.A.
1117 Hillsborough Street
Raleigh, North Carolina 27603

Robert F. Page
Attorney at Law
Crisp, Page & Currin, LLP
4010 Barrett Drive, Suite 205
Raleigh, NC 27609

Len S. Anthony /mhm

Len S. Anthony, General Counsel

Progress Energy Carolinas, Inc.'s CPCN Application for Sutton CC filed in Docket No. E-2, Sub 968 on December 18, 2009

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Progress Energy

December 18, 2009

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Ericson
Jones
Gruber
3-ps Legal
3-ps Acctg
2-ps Ec/Res
3-ps Elect
1-Hilburn

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

RE: Docket No. E-2, Sub 968

Enclosed for filing with the Commission are the original and 30 copies of Progress Energy Carolinas, Inc.'s ("PEC") Application for a Certificate of Public Convenience and Necessity to Construct a 620 Megawatt Combined Cycle Natural Gas Fueled Electric Generation Facility in New Hanover County at PEC's existing Sutton Plant site near the City of Wilmington and the supporting testimony of Glen A. Snider. Attachments 1, 2, 4 and 5 to this filing contain confidential information that must not be publicly disclosed. The original and ten copies of the unredacted version of Attachments 1, 2, 4 and 5 are attached in a sealed envelope marked "Confidential." PEC requests that the unredacted version be treated confidentially pursuant to N.C. Gen. Stat. § 132-1.2. Public disclosure of the information in Attachments 1 and 2 is prohibited by the Federal Energy Regulatory Commission's Order Nos. 702, 630, 630-A, 643 and 683 as it is Confidential Critical Energy Infrastructure Information. Public disclosure of the information in Attachments 4 and 5 would harm PEC's ability to negotiate favorable contracts for equipment and services, as well as purchased power contracts, because potential vendors would know the amounts PEC is willing to pay for such products and services and the facility's forecasted operating costs.

Also enclosed is a filing fee check in the amount of $250.00.

Yours very truly,

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

LSA:mhm

STAREG805

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

BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 968

In the Matter of Application of Progress Energy Carolinas, Inc. for a Certificate of Public Convenience and Necessity to Construct a 620 Megawatt Combined Cycle Natural Gas Fueled Electric Generation Facility in New Hanover County near the City of Wilmington and Motion for Waiver of Commission Rule R8-61(a) and (b)(4)	)))))))))))	**APPLICATION OF PROGRESS ENERGY CAROLINAS, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT A 620 MEGAWATT COMBINED CYCLE NATURAL GAS FUELED ELECTRIC GENERATION FACILITY IN NEW HANOVER COUNTY NEAR THE CITY OF WILMINGTON**

Pursuant to N.C. Gen. Stat. § 62-110.1 and § 62-300, and North Carolina Utilities Commission ("the Commission") Rules R1-3, R1-5, and R8-61, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. ("PEC") applies to the Commission for a Certificate of Public Convenience and Necessity to construct a 620 megawatt ("MW") combined cycle natural gas fueled electric generation facility at its existing Sutton Plant generation site in New Hanover County near the City of Wilmington, with an in-service date of December 2013.[1] In support thereof, PEC shows the following:

1. PEC is an electric public utility organized, existing and operating under the laws of North Carolina for the purposes of generating, transmitting and

[1] The proposed natural gas fueled facility will operate primarily on natural gas but will be capable of burning ultra-low sulfur no. 2 fuel oil.

distributing electricity in its service territories in North and South Carolina. Its principal offices are located at 410 S. Wilmington Street, Post Office Box 1551, Raleigh, NC 27602.

2. The attorneys to whom all communications and pleadings should be addressed are:

Len S. Anthony
General Counsel
P. O. Box 1551, PEB 17A4
Raleigh, NC 27602

Dwight W. Allen
The Allen Law Offices, PLLC
3737 Glenwood Avenue, Suite 100
Raleigh, North Carolina 27612

3. In PEC's Plan to Retire 550 MW of Coal Generation Without Sulfur Dioxide (SO_2) controls, filed December 1, 2009, in Docket No. E-2, Sub 960 (which is incorporated herein by reference), PEC described the environmental compliance challenges faced by its coal generation fleet. PEC's three coal units located at its Sutton Plant site have a generating capacity of 600 MWs. None of these units have any flue-gas desulphurization equipment to limit their emissions of mercury and SO_2. As more thoroughly explained below, the Coal Generation Retirement Plan stated that in order for PEC to continue operating the 600 MWs of coal generation at the Sutton Plant site in New Hanover County near Wilmington, PEC will, in all probability, be required to make significant investments in each unit to install equipment to control emissions of nitrogen oxides (NOx), sulfur

dioxide SO_2, and mercury (Hg), and purchase allowances for greenhouse gases (GHGs). In addition to installing additional controls to limit their airborne emissions, PEC will have to address foreseeable regulatory constraints associated with operating these environmental controls, such as their wastewater, as well as the by-products of combustion of coal, in particular bottom ash, fly ash, and scrubber by-products. These environmental regulatory requirements and the order in which they are expected to be encountered are generally as follows:

Mercury (Hg) and other hazardous air pollutants (HAPs)

4. In 2006, North Carolina adopted mercury emission regulations (15A NCAC 02D.02500) (N.C. Mercury Rules). The N.C. Mercury Rules establish mercury limits (15A NCAC 02D.2511), allocate emission allowances (15A NCAC 02D.2503) and require all coal-fired units to have mercury-control technology installed no later than December 31, 2017. The N.C. Mercury Rules are, in some respects, more stringent than the federal Clean Air Mercury Rule (CAMR) promulgated by the United States Environmental Protection Agency (EPA).

5. On February 8, 2008, the Court of Appeals for the District of Columbia Circuit vacated CAMR. The vacatur eliminated all mercury allowance trading and allocations under CAMR. However, the decision did not directly affect the N.C. Mercury Rules which remain in effect unless changed by state action. The N.C. Mercury Rules require PEC to develop an emission control plan for each operating unit by January 1, 2013, that identifies the schedule for

installation and operation of mercury controls. To meet this requirement, PEC will have to invest significant capital in control technologies or retire the coal unit. EPA is currently developing Maximum Achievable Control Technology (MACT) standards for mercury and other hazardous air pollutants emitted by steam generators that likely will result in further emission-reduction requirements. EPA is scheduled to propose the MACT in March 2011 with a final version expected in November 2011. PEC expects the mercury MACT and HAP compliance requirements to be in effect by 2014 or 2015.

Sulfur dioxide (SO_2)

6. Both the North Carolina Clean Smokestacks Act and the federal Clean Air Interstate Rule ("CAIR") require reductions in SO_2 emissions. By January 1, 2013, PEC is required by the Clean Smokestacks Act to reduce its annual North Carolina emissions of SO_2 from its coal fired plants to 50,000 tons or fewer. [G.S. Section 143-215.107D(e)(2)]. PEC will achieve the required reduction in 2013 by retiring the Lee coal units.

7. North Carolina adopted rules implementing CAIR, which were codified at 15A NCAC 02D .2401 et seq. (N.C. CAIR). N.C. CAIR also incorporated the CAIR allowance trading system under which an entity subject to CAIR could either reduce its emissions to the required limit, purchase sufficient allowances to comply with the rule's requirements, or undertake a combination of

both. CAIR would require further systemwide SO_2 emission reductions by 2015 or the purchase of allowances.

8. In July 2008, the Court of Appeals for the District of Columbia Circuit vacated federal CAIR. In substance, the Court found that the allowance trading system, which was an integral and essential part of CAIR, was inconsistent with the requirements of the federal Clean Air Act. In response to a petition by EPA, in December 2008, the Court modified its earlier opinion to remand the case to EPA without vacatur, in order to allow EPA to conduct further proceedings consistent with that prior opinion. EPA has noted that the withdrawal of the vacatur "means that CAIR....remain[s] in effect while EPA develops a replacement rule consistent with the [earlier] opinion." 74 Fed. Reg. 56722 (Nov. 3, 2009). In the interim, the N.C. CAIR remains in effect.

9. The revised federal CAIR is expected to require point-source-specific controls, rather than allowing an allowance trading compliance process. As a result, PEC's Sutton coal units will either have to be retired, or PEC will have to make significant investments in control technology. PEC anticipates the revised CAIR will require additional SO_2 reductions as early as 2015.

Carbon Dioxide (CO_2)

10. In response to the 2008 opinion of the U.S. Supreme Court in Massachusetts v. EPA, (549 U.S. 497, 127 S.Ct. 1438 (2007)), on December 7, 2009 EPA issued a final "endangerment finding," declaring that CO_2 and five other

greenhouse gases are pollutants that threaten public health and welfare. This finding gives EPA the authority to regulate CO_2 under the Clean Air Act.

11. On October 30, 2009, EPA issued a final rule requiring reporting of GHG emissions from sources emitting more than 25,000 metric tons of CO_2 per year. This rule goes into effect on December 29, 2009.

12. EPA has also issued a proposed rule applicable to stationary sources, including power plants that emit more than 25,000 tons per year of GHGs. The proposed rule links GHG regulation under Title V (operating permit program) and the Prevention of Significant Deterioration (PSD) portion of New Source Review (NSR). Under Title V, existing permits would not be modified to incorporate the GHG requirements until permit renewal. New or modified facilities that trigger PSD permitting requirements would need to apply for a revised permit that incorporates best available control technology (BACT) and energy efficiency measures to minimize GHG emissions. BACT for GHG has not been determined.

13. Concurrently, Congress is considering legislation to regulate GHGs. H.R.2454, the American Clean Energy and Security Act of 2009 (ACES), also known as the Waxman-Markey bill, was approved by the House of Representatives on June 26, 2009. In the Senate, S. 1733, the Clean Energy Jobs and American Power Act, also known as the Kerry-Boxer bill, has been introduced, and approved by a key committee. Both bills incorporate a three-pronged approach that proposes to (1) reduce national GHGs from industrial sources over a 38-year period, (2)

establish a market-based system for trading emission allowances, and (3) establish a GHG emissions reporting mechanism. Under both bills, actual source emissions are not restricted, but the ability to obtain allowances or offsets will be limited over the course of time as the national emissions caps are reduced. Many important differences exist between the House and Senate bills, including the EPA's authority to regulate GHGs. In contrast to the House bill, the Senate bill retains most of EPA's authority to regulate GHGs under the Clean Air Act.

14. In the absence of Congressional adoption of a statute to address CO_2 emissions, the EPA regulatory efforts are expected to continue. The EPA's endangerment finding provides a basis for regulating CO_2 under the existing provisions of the Clean Air Act and the possibility of requirements imposed in future and current air emission permits. It appears almost certain that there will be federal regulation of CO_2 emissions as well as other GHG emissions and precursors.

15. Finally, two recently issued federal appellate court decisions reinforce the assumption that regulation of GHGs will occur in the near future. On September 22, 2009, the U.S. Court of Appeals for the Second Circuit in Connecticut v. AEP et al., (582 F.3rd 309 (2009)) reinstated an action dismissed by a federal district court and held that those with standing can pursue claims of harm from CO_2 emissions if facts show that the injuries are "fairly traceable" to the defendant's CO_2 emissions and account for a significant percent of U.S. CO_2

emissions. The court held that the case could proceed on a "public nuisance" theory since there is no statutory framework that addresses the remedy requested by the plaintiffs. On October 16, 2009, the U.S. Court of Appeals for the Fifth Circuit in Comer v. Murphy Oil, USA, et al. (2009 WL 3321493 (5th Cir. 2009); Slip Op. No. 07-60756 (Oct. 16, 2009)) held that private parties have a right to pursue federal and state common law public and private nuisance, trespass and negligence claims against a wide range of energy companies alleging harm resulting from emissions of GHGs. Given that these are state law claims, federal regulation of GHGs may not necessarily extinguish the right to pursue all of the claims asserted.

16. All of the above indicate that GHGs, in particular carbon dioxide, likely will be subject to some form of regulation resulting in required emission reductions or purchases of allowances as early as 2012.

Coal Combustion Products (CCPs)

17. EPA is currently considering re-characterizing the nature of and regulation of coal combustion products (bottom ash, fly ash and related materials, hereinafter CCPs) in response to TVA's Kingston Plant ash pond impoundment failure. Speculation is focusing on EPA's regulation of CCPs as a hazardous waste. A narrow usage exclusion may be possible where the finished product of CCPs is fully encapsulated. Existing uses that involve land application or unconfined uses may be prohibited. If EPA characterizes CCPs as a hazardous

waste or otherwise increases the regulatory requirements applicable to CCPs, the handling, storage and disposal of this material will result in significantly increased costs of operation, and more sophisticated handling equipment and disposal requirements. Classification of power plant CCPs operations as activities that produce hazardous wastes as defined by the Resource Conservation and Recovery Act (RCRA) would trigger a number of additional regulatory requirements as well as potential liability associated with closure of impoundments, leachate management and site remediation. Phase out of surface impoundments is under consideration by EPA.

18. The current ash pond at PEC's Sutton Plant site will reach full capacity on or before 2014. As a result, if PEC continues operating the coal units at this site, even if the EPA does not characterize CCPs as a hazardous waste or otherwise increases the regulatory requirements applicable to CCPs, PEC must incur significant costs to construct a new ash pond or convert to dry ash handling together with design and permitting of onsite disposal capacity or transportation of the material offsite for disposal.

NOx, SO_2 & Particulate Matter

19. The revised federal CAIR is expected to require NOx and SO_2 reductions, which may also be driven by reasonably available control technology (RACT) limits necessary to achieve future ambient air-quality standards for ozone. In addition, revised and more stringent ambient air-quality standards for particulate

matter are expected to be issued in 2011, which might result in additional reduction requirements for that pollutant and its precursors (SO_2, NOx).

20. In addition, on December 8, 2009, EPA proposed a new 1-hour SO_2 ambient air quality standard. It is significantly more stringent than the current annual and 24-hour SO_2 ambient air quality standards. EPA is expected to finalize this revision in 2010.

How Do These Environmental Regulations Impact Continued Operations?

21. It is against this backdrop that PEC has evaluated the cost effectiveness of continuing to operate the three coal units at its Sutton Plant site. In performing this evaluation it must be emphasized that while SO_2 emissions controls ("scrubbers") may allow PEC to comply with additional mercury and SO_2 emissions reduction requirements, they provide no relief with regard to NOx, GHG emissions and CCP issues. Additional expenses associated with and investments in Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) for NOx control, dry ash handling and onsite or offsite disposal, CO_2 emission allowance purchase will be required to meet NOx, CCP and GHG environmental regulatory requirements.

Voltage Support Requirement

22. An important factor that has to be considered in evaluating whether to continue operating the three Sutton coal plants is the need for voltage support at this location on PEC's transmission system. Attachment 1 to this Application is a

map showing the eastern portion of the PEC system with the generation at the Sutton and Brunswick plants highlighted. This map assists in understanding the voltage support issue. The discussion of the Voltage Support Requirement is Confidential Critical Energy Infrastructure Information that cannot be publicly disclosed. This discussion is contained in Attachment 2 to this Application. Attachments 1 and 2 are attached hereto in a sealed envelope.

23. For the reasons explained in Attachment 2, it has been determined that a 2x1 natural gas combined cycle generator (CC) is the most cost effective replacement for the three Sutton coal units. A 2x1 CC facility optimizes site infrastructure resources such as existing local transmission capacity. The CC will be equipped with duct-firing capability to increase unit peaking capacity during periods of peak system demand. The CC will provide new summer non-fired CC capacity of approximately 550 MW to the PEC Control Area (and approximately 70 MWs of additional peaking capacity with duct-firing). Duct-firing (also known as supplemental firing) will be included to increase summer net capacity by approximately 70 MWs and allow the units to operate in a "fired" mode during periods of peak generation demand. During periods of average or low demand, the units could operate in an "unfired" mode, allowing for higher turndown rates and greater efficiency. The additional output generated by duct-firing can be available in 10 to 15 minutes. This design provides a level of reliability needed for this

location, increased response to peak generation demands, and system dispatch flexibility.

Economic Analysis

24. Based upon the information described above, PEC compared the cost of building a new approximately 620-MW 2x1 CC at the Sutton Plant location to the cost of continuing to operate the three existing coal units, including the cost of potential environmental modifications that could be required due to proposed emission regulations. The new CC and the existing coal units represent about the same amount of capacity.

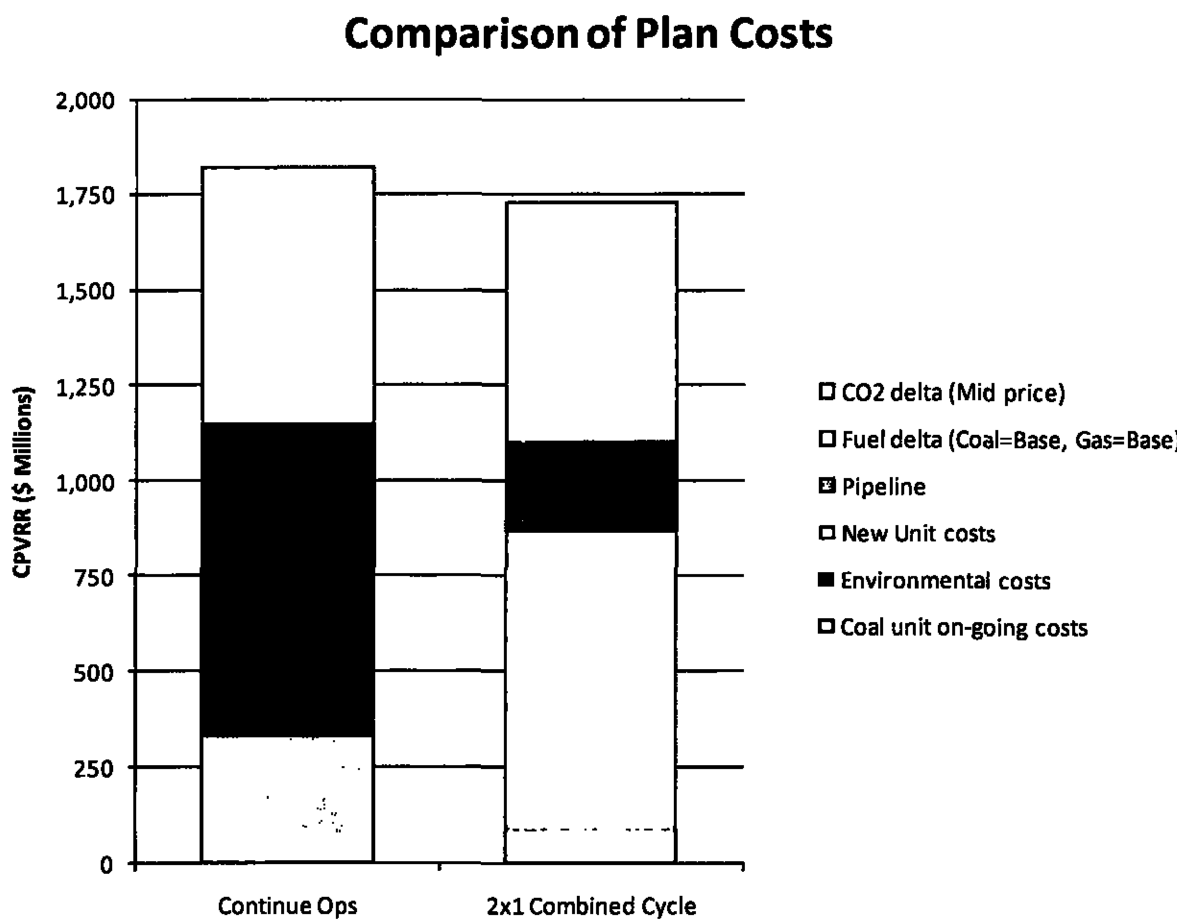
25. Continued operation of the Sutton coal units will require new SO_2, NOx and mercury emission controls as early as 2015. Continued operation will also require a new permitted landfill for ash and other coal combustion by-products. Retiring these coal units and replacing them with the 2x1 combined cycle eliminates the need for these controls and the new landfill, saving almost $720 million in capital expenditures, as shown in the table below.

Project	In-Service	Total Capital ($M)
Sutton 1&2 DFGD[2]	7/1/2014	216.0
Sutton 1&2 SNCR[3]	7/1/2013	16.8
Sutton 3 DFGD	1/1/2015	304.4
Sutton 3 SCR[4]	1/1/2015	159.6
Sutton CCP (initial)	7/1/2012	22.7
Total		719.5

[2] DFGD means Dry Flue Gas Desulphurization.
[3] SNCR means Selective Non-Catalytic Reduction.
[4] SCR means Selective Catalytic Reduction.

26. Retiring the coal units will also avoid ongoing operations and maintenance (O&M) and capital expenditures for the units. These costs are estimated to sum to over $670 million (nominal dollars) in O&M and over $285 million (nominal dollars) in capital through the 2009-2039 study period. These cost savings are partially offset by ongoing O&M and capital expenditures for the new combined cycle unit.

27. The economic analysis of the Sutton 2x1 CC was performed in terms of cumulative present value of revenue requirements (CPVRR). The stacked bar chart below shows the cost of retiring the Sutton coal units and replacing them with the 2x1 combined cycle unit is less than continuing the operation of Sutton coal units assuming future environmental regulations including CO_2. The total savings associated with retiring and replacing is approximately $90 million (CPVRR, 2009 dollars). The components of cost for each of the alternatives are represented by the different segments of the bars.



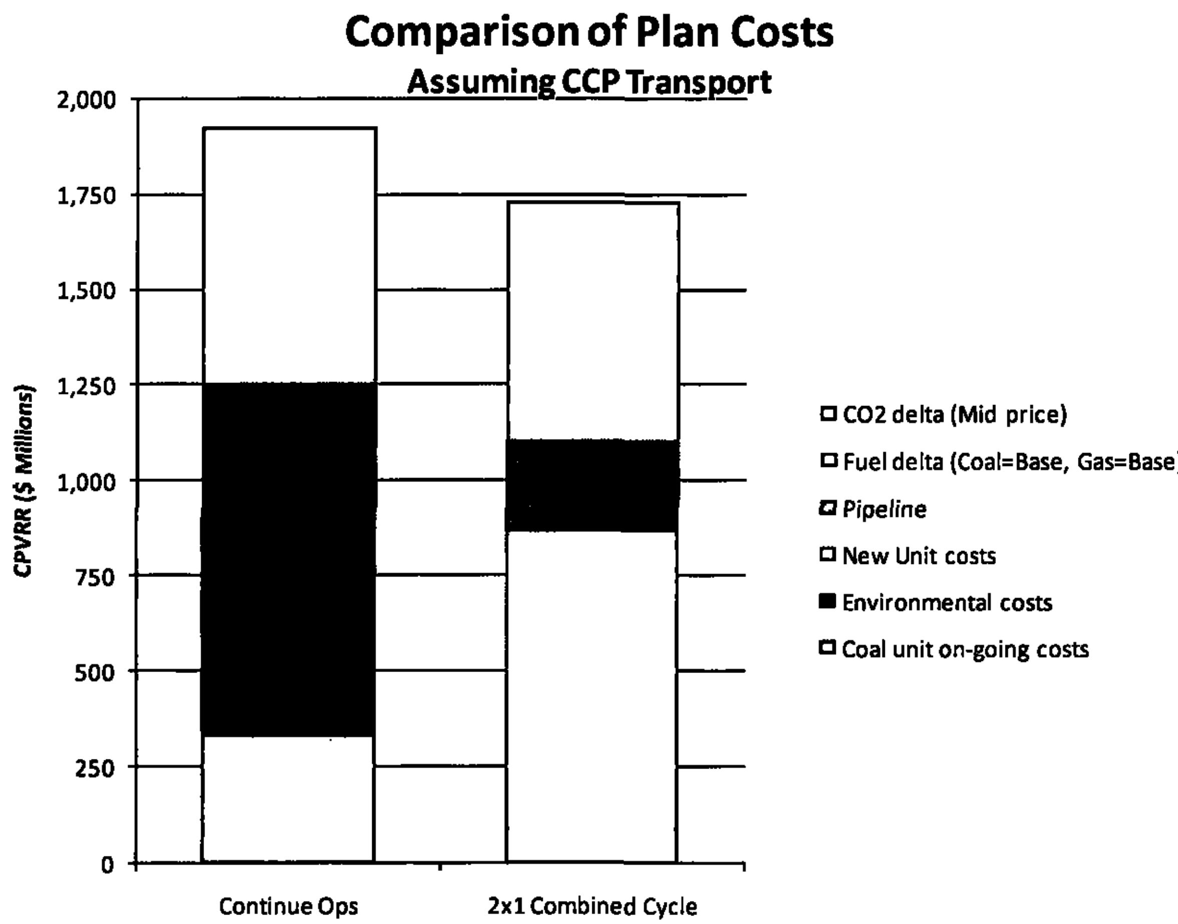
28. The cumulative present value of revenue requirements associated with SO_2 and NOx environmental controls on the coal units is approximately $795 million. PEC evaluated the likelihood of being required to install these controls and incur these costs. This evaluation included assessing the following environmental risks: the regulation of mercury and other air toxics, the CAIR revision, GHG regulation, and CCP management. PEC's evaluation concluded that regulation and/or management of these emissions/substances was highly probable and the inclusion of these costs in this analysis is appropriate.

29. For the Continued Operations case, the cost components were the ongoing O&M and capital costs to operate and maintain the Sutton coal units (the bottom blue segment); the cost of adding emission controls to the units (including O&M and consumables costs) and a new monofill for the plant, represented by the red segment; and the cost of CO_2 emissions, represented by the orange segment. The CO_2 emission differences considered were the difference in CO_2 emissions between the case with the Sutton 2x1 CC compared to the case with the Sutton coal units continuing operations.

30. For the 2x1 CC case, the cost components were the ongoing O&M and capital costs of the coal units until they are retired at the end of 2013; the O&M and capital costs of the new 2x1 combined cycle unit, represented by the green segment; the gas pipeline reservation costs, represented by the purple segment; and the change in total system fuel and purchase power costs from the Continued Operations case, represented by the aqua segment.

31. Construction of a new monofill for ash disposal would require a county "special use" permit. If a monofill cannot be built at the Sutton Plant site, the CCP would have to be transported to another location at an assumed cost of $55/ton. This would increase the cost of continuing to operate the coal units by over $440 million (nominal dollars) and more than $100 million net present value through the 2009-2039 study period. If transporting the CCP is required, the savings of retiring the coal units and replacing them with a 2x1 combined cycle

unit would be more than $192 million over the cost of continuing to operate the coal units, as shown in the chart below.

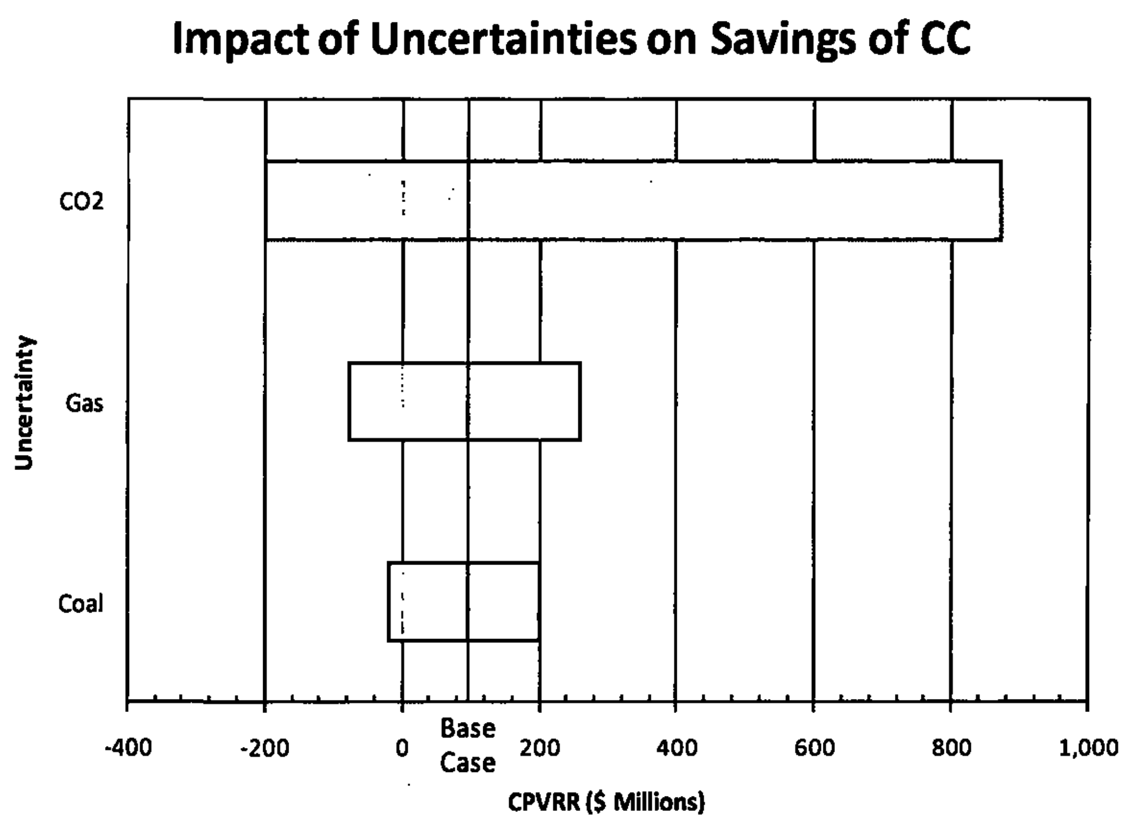


32. Three of the key uncertainties of the retire/replace decision were the cost of natural gas, the cost of coal, and the cost of CO_2 emissions. An analysis of these uncertainties was performed by examining 27 different combinations of the uncertainties, including the base price forecasts, plus- and minus-10 percent of the base fuel forecasts, and high and low CO_2 price forecasts.

33. The results of this analysis demonstrated that building a 2x1 CC at the Sutton Plant site was less costly than continuing to operate the coal units in 16 of

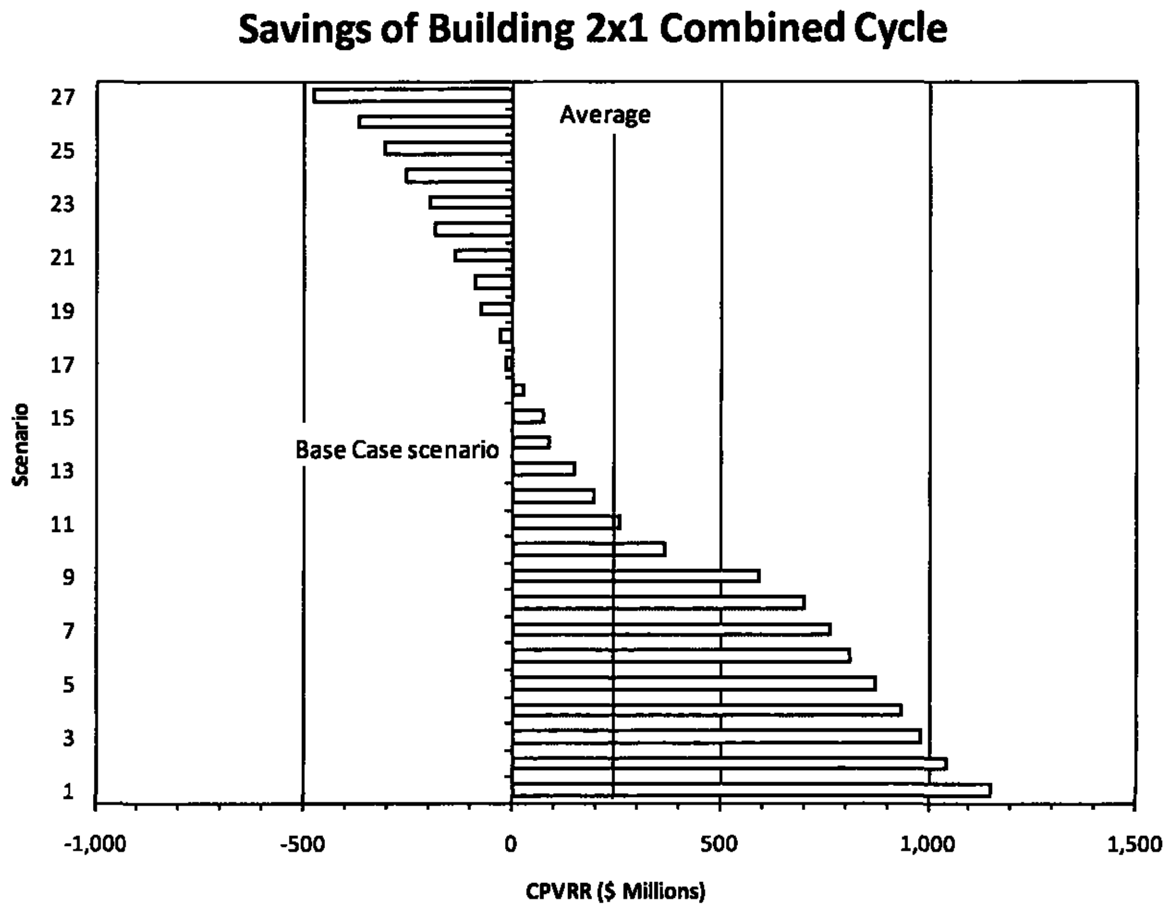
the 27 cases. The average savings associated with building the CC was over $254 million (CPVRR, 2009 dollars).

34. The range of the impact of any single uncertainty on the savings of building the CC is shown in the tornado chart below. As can be seen in the chart, the CO_2 price forecast has the largest range of impact.



35. The results of the 27 scenarios are shown in the figure below. Compared to the tornado diagram in the previous figure, which shows the range of impacts of a single uncertainty, this chart shows the range of impacts of the combinations of uncertainties. The figure also shows the average savings of the 27 scenarios and identifies the Base Case scenario that is represented in the stacked

bar charts. The results shown here assume a monofill is built (as opposed to transporting the coal combustion products) if the coal units continue to operate.



36. Thus, PEC concluded that given the range of variables, and evaluation of the uncertainties, building a 2x1 CC at the Sutton Plant site was the most cost effective and robust decision.

Rule R8-61(b) Filing Requirements

37. With regard to the filing requirements contained in Commission Rule R8-61(b), for items 1-3, PEC incorporates by reference its biennial integrated resource plan ("IRP") filed in Docket No. E-100, Sub 118 and its 2009 annual IRP

update filed in Docket No. E-100, Sub 124. Attached to this Application as Attachment 3 is an update to the 2009 annual report reflecting the addition of the proposed 620 MW combined cycle facility that is the subject of this Application. The 620 MW combined cycle facility for which PEC is seeking approval is not specifically included in or addressed in PEC's 2008 biennial IRP or 2009 IRP update. However, in the Overview of the 2009 IRP update PEC explained that PEC was considering numerous possible changes to its IRP including retiring additional coal plants and construction of additional natural gas combined cycle generators. At the time PEC filed its 2009 IRP update it had not conclusively decided to retire the three Sutton coal units and replace them with a 620 MW natural gas combined cycle facility. As a result, and given that the 2009 IRP was an update to the 2008 biennial IRP, PEC did not state in the 2009 update that the retirement and replacement of the Sutton coal units would occur. The impact on PEC's resource plan is shown in Attachment 3.

38. Item 4 of subsection (b) is not applicable as PEC was granted a waiver of this filing requirement.

39. The information required by items 5 and 6 is contained in confidential Attachment 4 to this Application.

40. For item 7, the projected effect of investment in the generating facility on PEC's overall revenue requirement for each year during the construction period, at this time PEC does not anticipate including CWIP in ratebase.

41. The anticipated construction schedule for the CC is:

Milestone		
New Generation	Baseline	Forecast
Award STG Contract	March 2010	Feb 2010
Award CTG Contract	Jan 2010	Dec 2010
Award HRSG Contract	Jan 2010	Jan 2010
Award EPC Contract	April 2010	April 2010
File for Air Permit	June 2010	June 2010
File Revised NPDES Permit Application	June 2010	June 2010
Mobilize Contractor for Site Preparation	Sep 2011	Sep 2011
Electrical Backfeed	Feb 2013	Feb 2013
Fuel Gas Available	Jun 2013	Jun 2013
First Fire	Aug 2013	Aug 2013
Commercial Operation	Dec 2013	Dec 2013

42. Regarding items 9 and 10, the specific type of units selected for the generating facility, the suppliers of the major components, and the basis for selecting the type of units, major components and suppliers, PEC explained above the basis for selecting a 620 MW 2x1 natural gas fueled CC as the preferred replacement resource. The CC will consist of two combustion turbines, two heat-recovery steam generators, and a steam turbine generator. PEC has issued requests for bids to the various vendors of these components and for the engineering, procurement and construction (EPC) services. Based upon price, performance and

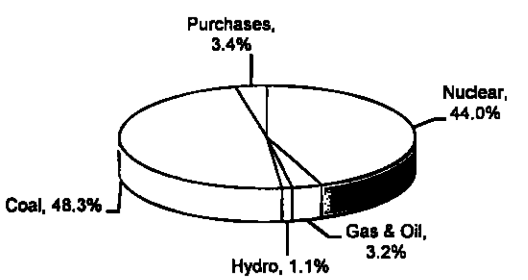
several other factors, PEC will select the vendors to provide the equipment and EPC services.

43. Continuing with item 9, regarding the adequacy of fuel supply long-term firm gas pipeline transportation capacity will be obtained to ensure a reliable fuel supply for the proposed new generation. On March 19, 2009, PEC issued an RFP soliciting proposals from natural gas transportation service providers including interstate pipelines, an intrastate pipeline and local distribution companies (LDCs) to begin the process of evaluating fuel requirements for the proposed new CC. The options currently being evaluated to serve the Sutton site are transportation service on Transco and Piedmont, and transportation service on Transco and Carolina Gas Transmission.

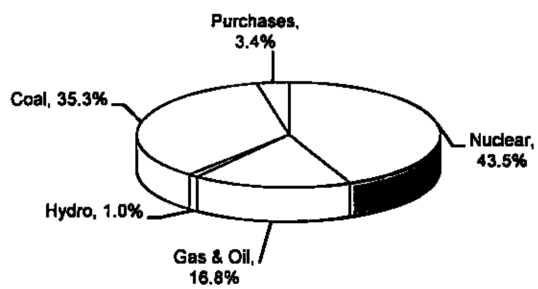
44. Regarding Item 11, resource and fuel diversity and reasonably anticipated future operating costs, including the anticipated in-service expenses associated with the CC for the twelve-month period of time following commencement of commercial operation of the CC, the forecasted operating costs are contained in Confidential Attachment 5. The new CC will improve PEC's resource and fuel diversity. Fuel diversity is enhanced by lowering the reliance upon coal and increasing the utilization of natural gas as a fuel source. The pie charts below illustrate this by comparing forecasted energy supply by fuel type from 2010 (before the Lee and Sutton coal units are retired) to 2014 (after the coal

units are retired and the Wayne County and Sutton CCs are placed in service).

2010 Energy by Fuel Type



2014 Energy by Fuel Type



45. Finally, regarding Item 12, the risk factors related to the construction and operation of the CC, one risk involves natural gas availability. If fuel gas delivery to the site is delayed beyond June 1, 2013, a resulting schedule compression could increase project cost and/or delay the commercial operation date. Regardless of which pipeline combination that is chosen, PEC will proactively monitor all pipeline development in order to anticipate any slippage that might occur under each of the respective pipeline project schedules. If PEC determines that Transco's project is at risk of meeting its schedule, PEC should be able to contract for short-term released capacity or bundled supply from the market to support testing through the Summer and Fall of 2013 to mitigate any delay in completion of Transco system upgrades with the expectation that CGT and or Piedmont are on time. Regarding construction risk, the primary environmental permit required before construction can begin on this project is the air permit. Because the project involves the retirement of the existing coal units, the air

emissions from the proposed CC facility with the appropriate emission controls are expected to be substantially reduced. Therefore, the new permit application is expected to qualify as a "minor" permit proceeding. As a minor permit proceeding, the final air permit would be expected to be issued by the N.C. Division of Air Quality in 6 to 12 months following application submittal. Other environmental permitting will be required for modification of the facility's National Pollutant Discharge Elimination System (NPDES) permit. A county development permit and a state Erosion & Sedimentation Control Plan will need to be approved for site development. If wetlands are impacted, a U.S. Army Corps of Engineers Dredge & Fill permit will be required. FAA notification of the height and location of the new emission stacks will be required. The facility's Spill Prevention, Control and Countermeasure Plan ("SPCC") and Emergency Response Plan will need to be revised.

46. PEC will not issue an RFP for purchased power options to replace the Sutton coal units. As explained earlier, due to voltage support requirements in the eastern region, the new plant must be located at a location that is essentially the same as the Sutton site. In addition, the existing site has the necessary transmission capability, water availability and rail access. PEC has the experience to properly manage the construction of natural gas fired combined cycle facilities, and will competitively bid all major equipment components and the EPC contract. Therefore there is no need to incur the costs of a third party to perform these tasks.

In addition, a resource this essential to the reliable and safe operation of PEC's system as a whole and the Brunswick Nuclear Plant, should be owned and operated by PEC.

47. Regarding any additional transmission investment, minimal investment will be required to connect the new CC with PEC's transmission system. No certificate is expected to be required for any of the transmission scope of work since connections are anticipated to be less than one mile and limited to onsite modifications. The new transmission facilities will consist of:

- A new 115-kV line between the new CC and the Sutton SE Plant 115 kV switchyard and install one new 115-kV circuit breaker;
- A new 230-kV line between the new 2x1CC and the Sutton SE Plant 230-kV switchyard and a new 230 kV circuit breaker;
- Conversion of the 230-kV switchyard to breaker-and-a-half scheme;
- Potentially construct a new control building for both 230- and 115-kV switchyard.

48. PEC therefore applies to the Commission for a certificate of public convenience and necessity pursuant to N.C. Gen. Stat. § 62-110.1 to construct a 2x1 CC that uses natural gas as its primary fuel at its Sutton Plant site with an in-service date of December 2013. If allowed to construct this natural gas fueled facility, upon its completion, PEC will permanently cease operations of the three coal fueled generating units totaling 600 MW at the Sutton Plant site.

WHEREFORE, PEC applies to the Commission for a Certificate of Public Convenience and Necessity to construct a 620-megawatt combined cycle natural gas fueled electric generation facility at its existing Sutton Plant in New Hanover County near the City of Wilmington.

Respectfully submitted this 18th day of December, 2009.

PROGRESS ENERGY CAROLINAS, INC.

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Raleigh, NC 27602
Telephone: (919) 546-6367
Email: Len.S.Anthony@pgnmail.com

ATTACHMENT 1 IS CONFIDENTIAL AND ENCLOSED IN SEPARATE CONFIDENTIALLY MARKED ENVELOPE.

ATTACHMENT 2
IS CONFIDENTIAL AND ENCLOSED IN SEPARATE CONFIDENTIALLY MARKED ENVELOPE.

Attachment 3

Progress Energy - Carolinas

2009 Annual IRP with Addition of Sutton CC (Summer)

12/18/2009

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
GENERATION CHANGES															
Sited Additions		635		950	620										
Undesignated Additions (1)				126				169	338	1,105	1,105				169
Planned Project Uprates		18	57		10	14									
Pollution Control Derates			(5)												
Retirements - Lee 1, 2, 3 & Sutton 1, 2, 3				(397)	(600)										

	2010	2011	2012	2013	2014	2015	2016	2017
INSTALLED GENERATION								
Nuclear	3,468	3,486	3,543	3,543	3,553	3,567	3,567	3,567
Fossil	5,179	5,179	5,175	4,778	4,178	4,178	4,178	4,178
Combined Cycle	543	1,178	1,178	2,128	2,748	2,748	2,748	2,748
Combustion Turbine	3,132	3,132	3,132	3,132	3,132	3,132	3,132	3,132
Hydro	228	228	228	228	228	228	228	228
Undesignated (1)				126	126	126	126	295
TOTAL INSTALLED *	12,550	13,203	13,256	13,935	13,965	13,979	13,979	14,148
PURCHASES & OTHER RESOURCES								
SEPA	95	95	95	109	109	109	109	109
NUG QF - Cogen								
NUG QF - Renewable **	25	25	28	35	40	19	19	19
NUG QF - Other								
AEP/Rockport 2								
Butler Warner			220	220	220	220	220	220
Anson CT Tolling Purchase				336	336	336	336	336
Broad River CT	829	829	829	829	829	829	829	829
Southern CC Purchase - ST	150	150						
Southern CC Purchase - LT	150	150	150	150	150	150	150	150
TOTAL SUPPLY RESOURCES	13,799	14,452	14,578	15,613	15,649	15,641	15,642	15,811
SYSTEM PEAK LOAD	12,731	12,913	13,099	14,122	14,361	14,624	14,854	15,091
Firm Sales	200	200	200	100	100	100	100	100
Energy Efficiency & Demand Response	502	636	797	882	963	1,043	1,126	1,210
System Firm Load after DSM	12,230	12,276	12,303	13,239	13,397	13,581	13,729	13,881
RESERVES (2)	1,569	2,175	2,275	2,374	2,251	2,060	1,913	1,929
Capacity Margin (3)	11%	15%	16%	15%	14%	13%	12%	12%
Reserve Margin (4)	13%	18%	18%	18%	17%	15%	14%	14%
ANNUAL SYSTEM ENERGY (GWh)	66,137	66,762	67,937	69,224	70,397	71,581	72,703	73,850

	2018	2019	2020	2021	2022	2023	2024
INSTALLED GENERATION							
Nuclear	3,567	3,567	3,567	3,567	3,567	3,567	3,567
Fossil	4,178	4,178	4,178	4,178	4,178	4,178	4,178
Combined Cycle	2,748	2,748	2,748	2,748	2,748	2,748	2,748
Combustion Turbine	3,132	3,132	3,132	3,132	3,132	3,132	3,132
Hydro	228	228	228	228	228	228	228
Undesignated (1)	633	1,738	2,843	2,843	2,843	2,843	3,012
TOTAL INSTALLED *	14,486	15,591	16,696	16,696	16,696	16,696	16,865
PURCHASES & OTHER RESOURCES							
SEPA	109	109	109	109	109	109	95
NUG QF - Cogen							
NUG QF - Renewable **	23	23	23	23	23	24	24
NUG QF - Other							
AEP/Rockport 2							
Butler Warner							
Anson CT Tolling Purchase	336	336	336	336	336	336	336
Broad River CT	829	829	829	339			
Southern CC Purchase - ST							
Southern CC Purchase - LT	150	150					
TOTAL SUPPLY RESOURCES	15,932	17,037	17,992	17,502	17,164	17,164	17,319
SYSTEM PEAK LOAD	15,316	15,557	15,808	16,061	16,317	16,576	16,840
Firm Sales	100	100	100	100	100	100	100
Energy Efficiency & Demand Response	1,290	1,365	1,427	1,474	1,519	1,561	1,600
System Firm Load after DSM	14,026	14,192	14,381	14,586	14,798	15,015	15,240
RESERVES (2)	1,906	2,846	3,611	2,916	2,366	2,149	2,079
Capacity Margin (3)	12%	17%	20%	17%	14%	13%	12%
Reserve Margin (4)	14%	20%	25%	20%	16%	14%	14%
ANNUAL SYSTEM ENERGY (GWh)	74,916	75,951	77,108	78,293	79,586	80,855	82,140

Notes:

* TOTAL INSTALLED includes Mod-24 unit rating changes.

** Renewables are assumed to be provided by sources that are dispatchable and/or high capacity factor sources and therefore are counted towards capacity margin. The MW shown include potential sources that have not yet been identified but are expected to be obtained to meet PEC's Renewable Portfolio Standard requirements.

Footnotes:

(1) Undesignated capacity may be replaced by purchases, uprates, DSM; or a combination thereof. Joint ownership opportunities will be evaluated with baseload additions.
(2) Reserves = Total Supply Resources - Firm Obligations
(3) Capacity Margin = Reserves / Total Supply Resources * 100.
(4) Reserve Margin = Reserves / System Firm Load after DSM * 100.

ATTACHMENT 4
IS CONFIDENTIAL AND ENCLOSED IN SEPARATE CONFIDENTIALLY MARKED ENVELOPE.

ATTACHMENT 5
IS CONFIDENTIAL AND ENCLOSED IN SEPARATE CONFIDENTIALLY MARKED ENVELOPE.

**STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH**

DOCKET NO. E-2, SUB 968

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application of Progress Energy Carolinas, Inc. for a Certificate of Public Convenience and Necessity to Construct a 600 Megawatt Combined Cycle Natural Gas Fueled Electric Generation Facility in New Hanover County near the City of Wilmington and Motion for Waiver of Commission Rule R8-61(a) and (b)(4)	)	**VERIFICATION AND SIGNATURE**

PERSONALLY APPEARED before me, Glen A. Snider, who, after first being duly sworn, said that he is the Manager – Resource Planning with Progress Energy Carolinas, Inc. and as such is authorized to make this Verification that the facts contained in the attached Application for a Certificate of Public Convenience and Necessity and Supporting Testimony are true and accurate.

Glen A. Snider

Glen A. Snider

Sworn to and subscribed before me,
this the 18th day of December, 2009.

Marsha H. Manning

MARSHA H MANNING
NOTARY PUBLIC
WAKE COUNTY, NC
My Commission Expires 10-3-2014

STAREG835

STATE OF NORTH CAROLINA
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 968
DIRECT TESTIMONY OF GLEN A. SNIDER

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. I am employed by Progress Energy Carolinas, Inc. ("PEC") as Manager of Resource Planning in the Transmission Operations & Planning Department. My business address is 100 E. Davie Street, Raleigh, North Carolina 27601.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. My educational background includes a bachelor of science in mathematics and a bachelor of science in economics from Illinois State University. With respect to professional experience I have been in the industry for twenty years. I started as an associate analyst with the Illinois Department of Energy and Natural Resources responsible for assisting in the review of Illinois utilities' integrated resource plans. In 1992, I accepted a planning analyst position with Florida Power Corporation and for the past ten years have held various management positions within the industry. These positions have included managing the risk analytics group for Progress

Ventures, the wholesale transaction structuring group for ArcLight Energy Marketing and my current position as Manager of Resource Planning for Progress Energy Carolinas.

Q. BRIEFLY STATE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to support and sponsor PEC's Application for a Certificate of Public Convenience and Necessity to construct a new combined-cycle generating facility totaling approximately 620 MWs at its Sutton Plant location in New Hanover County near the City of Wilmington with an in-service date of December 1, 2013. I am sponsoring PEC's Application including Attachments as PEC Exhibit No. 1.

Q. WHY DOES PEC NEED TO CONSTRUCT THIS NEW GENERATING FACILITY?

A. PEC's Application for a Certificate of Public Convenience and Necessity to construct the proposed natural gas combined cycle facility describes in great detail why PEC needs to build this generating facility. Fundamentally, PEC has determined that the cost of continuing to operate its existing 600 MWs of coal fired generation at the Sutton Plant site is greater than the cost of retiring those coal units and replacing them with a new natural gas fired combined cycle generating facility.

Q. PLEASE DESCRIBE THE PROPOSED NATURAL GAS FIRED COMBINED CYLCE GENERATING FACILITY.

A. The new combined-cycle generating facility will consist of two combustion turbines and two heat recovery steam generators to produce steam to drive a single steam turbine. The summer output of the combined cycle facility will be approximately 550MWs. However, the facility will be equipped with duct firing capability which increases its generating capacity to approximately 620 MWs during peak conditions. The facility's operating states are explained in more detail in the Certificate Application. The two combustion turbines will be primarily fueled by natural gas; however, they will be capable of running on ultra low sulfur fuel oil if natural gas is not available due to unforeseen circumstances. The facility will have bypass dampers installed to ensure that the plant can be operated in simple-cycle or combined-cycle mode to enhance reliability and operational flexibility. As a result of the overall efficiency of the combined-cycle process, this new facility will be operated as an intermediate load resource with capacity factors in the range of 30% to 60%.

Q. WHY HAS PEC CHOSEN COMBINED-CYCLE AS THE TYPE OF GENERATING CAPACITY TO INSTALL?

A. As explained in PEC's 2008 Biennial Integrated Resource Plan and 2009 update, gas-fired generators are the most environmentally benign, economical, large-scale capacity additions available for meeting peaking and intermediate loads. New designs of these technologies are more efficient (as measured by heat rate) than previous designs, resulting in a smaller impact on the environment. The advancements associated with combined-cycle operation and design provides greater operational flexibility relative to combustion turbines without heat recovery steam generators and steam turbines. This is due to several factors. First, each combustion turbine can be operated in a simple-cycle mode or in concert with its heat recovery steam generator and the steam turbine to enhance reliability and optimize unit operations. Second, the combined-cycle has approximately 70 MWs of duct firing capability that can be dispatched during peak demand periods, much the same way as a peaker, but at a fraction of the cost of installing an additional combustion turbine. Third, a combined-cycle unit can be economically utilized across a wide capacity range, approximately 30% to 60%, which means it can grow with system energy needs unlike oil fired combustion turbines which are logistically and environmentally hindered from operating at capacity factors greater than roughly five to ten percent. It should also be noted that combined cycle technology has an additional benefit within PEC's balanced solution of providing fuel diversity and lowering long term fuel price volatility.

Q. WHAT ARE THE ENVIRONMENTAL BENEFITS OF COMBINED-CYCLE GENERATION?

A. The combined-cycle facility fueled by natural gas is the cleanest and most efficient fossil fueled generation currently available. There are virtually no sulfur dioxide (SO_2) emissions, and nitrogen oxide (NO_x) emissions are approximately 80 percent less than new coal-fired generation. Further, the gas fired combined-cycle facility will help PEC adapt to and comply with any carbon legislation because its emissions of carbon dioxide are approximately 60% less than new coal generation of equivalent capacity.

Q. IS THE PROPOSED COMBINED-CYCLE FACILITY THE LEAST COST RESOURCE TO REPLACE THE EXISTING SUTTON COAL UNITS?

A. Yes. Combined-cycle generating capacity is the least cost source of reliable intermediate capacity available. Since 1997, PEC has placed in-service approximately 2,230 MW of new combustion turbines and 480 MW of combined-cycle capacity. Combined-cycle capacity minimizes the usage of higher cost oil fired combustion turbines. PEC has extensive experience in both negotiating the purchase of these facilities as well as their installation and construction. The equipment and the engineering, procurement and construction work will be procured in accordance with PEC guidelines which provide for both technical and commercial evaluations of bids. PEC will invite proposals from different equipment vendors for the purchases of the combustion turbine generators (CTGs) and other items of major equipment. PEC will also request bids from available and qualified engineering and construction firms to construct the facility. As a result, the combined-cycle facility will be the result of a competitive bidding process. PEC will not seek purchased power alternatives for this resource need. As thoroughly described in the Application, due to voltage support requirements in this area as well as the needs of the Brunswick Nuclear Plant, the replacement generation must be built at the existing Sutton Plant site. Given the importance of this generating capacity to the eastern region and PEC's experience in procuring the necessary equipment and engineering and construction services, purchased power options are not viable or productive.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

2012 Near Term Decommissioning Study for Cape Fear, Lee, Sutton and Weatherspoon

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Report on the

Decommissioning Cost Study Near-Term Units to be Decommissioned

Progress Energy Carolinas

Project No. 62009

January 2012

January 27, 2012

Mr. Issa Zarzar
Manager – Plant Decommissioning Projects
Progress Energy, Inc.
410 South Wilmington Street
Raleigh, North Carolina 27601

Re: Decommissioning Cost Study
BMcD Project No. 62009

Dear Mr. Zarzar:

Burns & McDonnell (BMcD) is pleased to submit this Decommissioning Cost Study prepared on behalf of Progress Energy Carolinas (Progress).

BMcD was retained by Progress to conduct a Decommissioning Cost Study (Study) for power generation assets in North Carolina and South Carolina, excluding nuclear units. The assets include natural gas, fuel oil, hydro-electric, and coal-fired generating facilities. Individuals from BMcD visited each of the Plants covered by the Study in July of 2011, along with a representative from LVI Services (LVI), a demolition contractor who is serving as a sub-consultant to BMcD on the Study. The purpose of the Study was to review the facilities and to make a recommendation to Progress regarding the total cost to decommission the facilities at the end of their useful lives.

The attached report presents the results of the Study, along with the cost estimates for decommissioning each of the facilities. The included costs are presented in 2011 dollars.

If you need any additional information, please contact me at (816) 822-4239 or jkopp@burnsmcd.com. It is a pleasure to be of service to Progress in this matter.

Sincerely,

Jeffrey T Kopp

Jeff Kopp, PE
Project Manager

cc: Vic Ranalletta, PE - BMcD
Jeff Pope, PE - BMcD
Michael Marcheschi - LVI

Decommissioning Cost Study

prepared for

Progress Energy Carolinas
Raleigh, North Carolina

January 2012

Project No. 62009

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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EXECUTIVE SUMMARY

ES.0 EXECUTIVE SUMMARY

ES.1 INTRODUCTION

Burns & McDonnell (BMcD) was retained by Progress Energy Carolinas (Progress) to conduct a Decommissioning Cost Study (Study) for power generation assets (Plants) in North Carolina and South Carolina, excluding nuclear units. The assets include natural gas, fuel oil, hydro-electric, and coal-fired generating facilities. Individuals from BMcD visited each of the Plants covered by the Study in July of 2011, along with a representative from LVI Services (LVI), a demolition contractor who is serving as a sub-consultant to BMcD on the Study. The purpose of the Study was to review the facilities and to make a recommendation to Progress regarding the total cost to decommission the facilities at the end of their useful lives.

The decommissioning costs were developed using the information provided by Progress, in-house data available to BMcD, and information supplied by LVI. Quantity take-offs were performed for major plant facilities and equipment based on observations from the site visits and review of drawings provided for each Plant. Decommissioning activities were determined and labor hours were estimated to complete each decommissioning activity. Current market pricing for labor rates and unit pricing were then developed for each task, and these rates were applied to the estimated quantities for the Plants to determine the total cost of decommissioning.

ES.2 RESULTS

BMcD has prepared estimates in current dollars (2011$) for the decommissioning of the Plants. These costs are summarized in Table ES-1. When Progress determines that the Plants should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the decommissioning costs. Progress will incur costs in the demolition and restoration of the sites less the salvage value of equipment and bulk steel.

Table ES-1: Decommissioning Cost Summary

Asset	Decommissioning Costs	Credits	Net Project Cost
Cape Fear	$62,571,000	($11,608,000)	$50,963,000
Lee	$76,963,000	($9,410,000)	$67,553,000
Sutton	$53,465,000	($10,070,000)	$43,395,000
Weatherspoon	$26,806,000	($4,806,000)	$22,000,000

The total project costs presented above include the costs to return the sites to an industrial condition suitable for reuse for development of an industrial facility. Included are the costs to dismantle the power generating equipment owned by Progress as well as the costs to dismantle the Progress owned balance of plant facilities and environmental site restoration activities.

ES.3 STATEMENT OF LIMITATIONS

In preparation of this decommissioning study, BMcD has relied upon information provided by Progress Energy. BMcD acknowledges that it has requested the information from Progress Energy that it deemed necessary to complete this study. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer’s estimates and projections of decommissioning costs are based on Engineer’s experience, qualifications and judgment. Since Engineer has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors’ procedures and methods, and other factors, Engineer does not guarantee the accuracy of its estimates and projections.

Engineer’s estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

* * * * *

SECTION 1
INTRODUCTION

1.0 INTRODUCTION

1.1 BACKGROUND

Burns & McDonnell (BMcD) was retained by Progress Energy Carolinas (Progress) to conduct a Decommissioning Cost Study (Study) for power generation assets (Plants) in North Carolina and South Carolina, excluding nuclear units. The assets include natural gas, fuel oil, hydro-electric, and coal-fired generating facilities. Individuals from BMcD visited each of the Plants covered by the Study in July of 2011, along with a representative from LVI Services (LVI), a demolition contractor who is serving as a sub-consultant to BMcD on the Study. The purpose of the Study was to review the facilities and to make a recommendation to Progress regarding the total cost to decommission the facilities at the end of their useful lives.

The decommissioning costs were developed using the information provided by Progress, in-house data available to BMcD, and information supplied by LVI. Quantity take-offs were performed for major plant facilities and equipment based on observations from the site visits and review of drawings provided for each Plant. Decommissioning activities were determined and labor hours were estimated to complete each decommissioning activity. Current market pricing for labor rates and unit pricing were then developed for each task, and these rates were applied to the estimated quantities for the Plants to determine the total cost of decommissioning.

1.2 STUDY METHODOLOGY

The site decommissioning costs were developed using information provided by Progress, information developed by LVI, and in-house data BMcD has collected from previous project experience. BMcD estimated quantities for equipment based on a visual inspection of the facilities, review of engineering drawings, BMcD's in house database of plant equipment quantities, along with LVI and BMcD's professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each decommissioning effort. Current market pricing for labor rates, equipment, and unit pricing were then developed for each task. The unit pricing was developed for each site based on the labor rates, equipment costs, and disposal costs specific to the area in which the work is to be performed. These rates were applied to the quantities for the Plants to determine the total cost of decommissioning for each site.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to decommission all of the assets owned by Progress at the site, including power generating equipment and balance of plant facilities

1.3 SITE VISITS

Representatives from BMcD and LVI visited the sites. The site visit consisted of a tour of the Facility with Plant personnel to review the equipment installed at the site. Tours were conducted by Plant personnel.

Mr. Paul Desai, from Progress Energy, served as the Progress representative throughout the site visits, along with plant personnel at each of the sites.

The following BMcD representatives comprised the site visit team:

- Mr. Jeff Kopp, Project Manager
- Mr. Vic Ranalletta, Lead Engineer
- Mr. Jeff Pope, Lead Environmental

In addition, Mr. Jeff Grubich, Environmental Specialist, filled in for Mr. Jeff Pope on several of the site visits. The site visits were performed on the following dates.

Table 1-1: Site Visit Dates

Asset	Site Visit Date
Cape Fear	July 18, 2011
Lee	July 20, 2011
Sutton	July 21, 2011
Weatherspoon	July 21, 2011

* * * * *

SECTION 2

PLANT DESCRIPTIONS

2.0 PLANT DESCRIPTIONS

2.1 CAPE FEAR

The Cape Fear site is located southwest of Raleigh, in Moncure, North Carolina. The plant includes four coal fired stoker units that are no longer in operation, as well as two units currently operating at a total capacity of approximately 316 MW. Units 1 through 4 do not include electrostatic precipitators, but Units 5 and 6 include electrostatic precipitators. None of the units include SCR systems or FGD systems. The four coal units that were taken out of service were repowered with combustion turbines and heat recovery steam generators. The combustion turbines include bypass stacks so they can be run in simple cycle mode. The plant site also includes active ash ponds and several inactive ash ponds.

2.2 LEE

The Lee plant is located in Goldsboro, North Carolina. The facility includes three coal-fired units rated at a total capacity of 397 megawatts. The units include electrostatic precipitators, but do not include SCR systems or FGD systems. The plant site includes a cooling lake and several ash ponds. In addition to the coal-fired units, the plant includes three Westinghouse 251 IC combustion turbines and one Westinghouse 191 IC combustion turbine, all operating in simple cycle mode.

2.3 SUTTON

The Sutton plant is located near the city of Wilmington, North Carolina. The facility consists of three coal-fired units totaling 604 megawatts. The units include electrostatic precipitators, but do not include SCR systems or FGD systems. The plant also includes two Westinghouse 191 IC combustion turbines and one Westinghouse 301 combustion turbine, all operating in simple cycle mode. The plant site includes a cooling lake and ash ponds.

2.4 WEATHERSPOON

The Weatherspoon plant is located in Lumberton, North Carolina. The facility consists of three coal-fired units totaling 171 megawatts. The units include electrostatic precipitators, but do not include SCR systems or FGD systems. The plant also includes four Pratt & Whitney combustion turbines, all operating in simple cycle mode. The plant site includes a cooling lake and an ash pond.

* * * * *

SECTION 3

DECOMMISSIONING COSTS

3.0 DECOMMISSIONING COSTS

BMcD has prepared decommissioning cost estimates for the Plants. When Progress determines that each site should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the site decommissioning costs. However, Progress will incur costs of decommissioning of the Plants and restoration of the site to the extent that those costs exceed the salvage value of equipment and bulk steel.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to dismantle all of the assets owned by Progress at the site, including power generating equipment and balance of plant facilities, as well as environmental site restoration activities.

For purposes of this study, BMcD and LVI have assumed that each site will be decommissioned as a single project, allowing the most cost effective demolition methods to be utilized. A summary of several of the means and methods that could be employed is summarized in the following paragraphs; however, means and methods will not be dictated to the contractor by BMcD. It will be the contractor’s responsibility to determine means and methods that result in safely decommissioning the Plants at the lowest possible cost.

Asbestos remediation would take place prior to commencement of any other demolition activities. Abatement would need to be performed in compliance with all state and federal regulations, including, but not limited to requirements for sealing off work areas and maintaining negative pressure throughout the removal process. Final clearances and approvals would need to be achieved prior to performing further demolition activities.

High grade assets would then be removed from the site, to the extent possible. This would include items such as transformers, transformer coils, circuit breakers, electrical wire, condenser plates and tubes, and heater tubes. High grade assets include precious alloys such as copper, aluminum-brass tubes, stainless steel tubes, and other high value metals occurring in plant systems. High grade asset removal would occur up-front in the schedule, to reduce the potential for vandalism, to increase cash flow, and for separation of recyclable materials, in order to increase scrap recovery. Methods of removal vary with the location and nature of the asset. Small transformers, small equipment, and wire would likely be removed and shipped as-is for processing at a scrap yard. Large transformers, combustion turbines, steam turbines, and condensers would likely require some on-site disassembly prior to being shipped to a scrap yard.

Construction and Demolition (C&D) waste includes items such as non-asbestos insulation, roofing, wood, drywall, plastics, and other non-metallic materials. C&D waste would typically be segregated from scrap and concrete to avoid cross-contaminating of waste streams or recycle streams. C&D demolition crews could remove these materials with equipment such as excavators equipped with material handling attachments, skid steers, etc. This material would be consolidated and loaded into bulk containers for disposal.

In general, boilers and HRSGs could be felled and cut into manageable sized pieces on the ground. First the structures around the boilers would need to be removed using excavators equipped with shears and grapples. Stairs, grating, elevators, and other high structures would be removed using an "ultra high reach" excavator, equipped with shears. Following removal of these structures, the boilers or HRSGs would be felled, using explosive blasts. The boilers would then be dismantled using equipment such as excavators equipped with shears and grapples, and the scrap metal loaded onto trailers for recycling.

After the surrounding structures and ductwork have been removed, the stacks would be imploded, using controlled blasts. Following implosion the stack liners and concrete would be reduced in size to allow for handling and removal.

Balance of plant structures and foundations would likely be demolished using excavators equipped with hydraulic shears, hydraulic grapples, and impact breakers, along with workers utilizing open flame cutting torches. Steel components would be separated, reduced in size, and loaded onto trailers for recycling. Concrete would be broken into manageable sized pieces and stockpiled for crushing on-site. Concrete pieces would ultimately be loaded in a hopper and fed through a crusher to be sized for on-site disposal.

3.1 GENERAL DECOMMISSIONING ASSUMPTIONS FOR ALL SITES

The following assumptions were made as the basis of all of the cost estimates.

1. The estimates are inclusive of all cost necessary to properly dismantle and decommission all sites to a marketable or usable condition. For purposes of this study and the included cost estimates, the facilities will be restored to a condition suitable for industrial use.

2. All facilities will be decommissioned to zero generating output. Existing utilities will remain in place for use by the contractor for the duration of the demolition activities.
3. All work will take place in the most cost efficient method.
4. Labor costs are based on a regular 40 hour workweek without overtime.
5. It is assumed that all the power stations will be dismantled after all units at a single site are taken out of service, allowing dismantlement of entire sites at once.
6. Soil testing and any other on-site testing has not been conducted for this study.
7. Transmission switchyards and substations within the boundaries of the plant are not part of the demolition scope. Switchyards that are associated with the facilities only and are not part of the transmission system are included for demolition. For purposes of this study, the division between generation assets and transmission assets is at the high side of the generator step-up transformers.
8. The costs for relocation of transmission lines, or other transmission assets, are specifically excluded from the decommissioning cost estimates. Any costs necessary to support on-going operations of adjacent or newly proposed units will be allocated to the operating costs of the units not being decommissioned.
9. Step up transformers, auxiliary transformers, and spare transformers are included for demolition and scrap in all estimates.
10. Abatement of asbestos will precede any other work. After final air quality clearances have been reached, demolition can proceed.
11. All demolition and abatement activities, including removal of asbestos, will be done in accordance with any and all applicable Federal, State and Local laws, rules and regulations.
12. Progress Energy will remove or consume all burnable coal, fuel oil and chemicals prior to commencement of demolition activities.
13. If any PCB contaminated oil is encountered, it will be removed and disposed of properly. Estimated quantities of PCB contaminated oil were developed for each site based on data provided by Progress Energy.
14. Hazardous material abatement is included for all sites as necessary, including asbestos, mercury, and PCBs. Lead paint coated materials will be handled by certified personnel as necessary, but will not be removed prior to demolition.
15. No environmental costs have been included to address cleanup of contaminated soils, hazardous materials, or other conditions present on-site having a negative environmental impact, other than those specifically listed in these assumptions. No allowances are included for unforeseen environmental remediation activities.

16. Handling and disposal of hazardous material will be performed in compliance with the approved methods of Progress Energy Environmental Services Department.
17. Refractory brick on the coal fired boilers is handled and disposed of as hazardous waste, due to the likelihood of the presence of arsenic contamination.
18. Existing ash ponds will be pumped dry, filled with inert debris, capped with 40 mil geo-membrane, geo-net drainage layer, 18 inches of soil, and vegetated cover.
19. Stormwater ponds will be pumped dry, filled with inert debris, capped with 40 mil geo-membrane, geo-net drainage layer, 18 inches of soil, and vegetated cover.
20. Cooling lakes will remain as-is, with the exception of the Weatherspoon site. The Weatherspoon cooling lake will require dredging of ash from an area of the pond prior to being abandoned.
21. Site areas will be graded to achieve suitable site drainage to natural drainage patterns, but grading will be minimized to the extent possible.
22. All above grade structures will be demolished. All below grade structures, including foundations, will be abandoned in-place unless deemed hazardous by Progress Energy or otherwise stated in the assumptions as being demolished.
23. All roads, paving, crushed rock surfacing, and rail lines will be abandoned in place, and be available for reuse.
24. Existing basements will be used to bury non-hazardous debris. Concrete in trenches and basements will be perforated to create drainage. Non-hazardous debris, such as concrete and brick, will be crushed and used as clean fill on-site once the capacity of all existing basements has been exceeded. All inert debris is disposed on-site, with the exception of the hydro-electric plants. Costs for offsite disposal are included for materials not classified as inert debris, and for all debris at the hydro-electric plants.
25. Major equipment, structural steel, combustion turbines, generators, inlet filters, exhaust stacks, transformers, electrical equipment, cabling, wiring, pump skids, above ground piping, and equipment enclosures for the above equipment are sold for scrap and removed from the Plant site by the demolition contractor. All other demolished materials are considered debris.
26. Except for the circulating water lines, underground piping will be abandoned in place. Circulating water system pipes will be capped, have the tops broken out, and backfilled with on-site soil.
27. Sewers, catch basins and ducts will be filled and sealed on the upstream side. Horizontal runs will be abandoned in place after being closed.

28. Costs are included to clean out the fuel oil tanks and lines. Costs have also been included to remove one foot of soil directly below each of the fuel oil tanks to account for the potential for this soil to be contaminated during normal operations.
29. Disturbed site areas will be seeded after they are graded to provide a suitable ground cover to prevent soil erosion.
30. Spare Parts inventories have been provided to BMcD by Progress Energy. It is assumed that spare parts having potential reuse will be transferred to other Progress Energy sites or sold on the secondary market prior to commencing dismantlement. For purposes of this study, BMcD has assumed that any spare parts, tools, inventory, or equipment in the buildings will be salvaged or sold for scrap, the value of which has been accounted for in the estimates.
31. Rolling stock, including rail cars, dozers, plant vehicles, etc. is assumed to be removed by Progress Energy prior to decommissioning.
32. Valuation and sale of land and all replacement generation costs are excluded from this scope.
33. For purposes of this study, it is assumed that none of the equipment will have a salvage value in excess of the scrap value of the materials in the equipment at the time of the decommissioning study. The decommissioning cost estimate is based on the end of useful life of each facility. All equipment, steel, copper, and other metals will be sold as scrap. Credits for salvage value are based on scrap value alone. Resale of equipment and materials is not included.
34. The scope of the costs included in this Study is limited to the decommissioning activities that will occur at the end of useful life of the facilities. Additional on-going costs may be required, including, but not limited to groundwater monitoring associated with ash pond closure and/or other environmental monitoring activities. These costs are excluded from the cost estimates provided in this Study.
35. Contingency is included in the cost estimate to cover expenses that are unknown at the time the estimate is prepared, but can reasonably be anticipated to be expended on the project. When preparing a cost estimate, there is always some uncertainty as to the precision of the quantities in the estimate, how work will be performed, and what work conditions will be like when the project is executed. Uncertainties are greater in a demolition project than in a construction project due to the nature of the drawings used for quantity takeoffs and the likelihood of encountering unknown conditions, such as hazardous materials, or environmental contamination. Other unknown conditions that could impact the costs include, but are not limited to, changing market conditions and weather delays. These uncertainties will impact the actual costs of the project relative to the estimated cost. The estimator is aware of these unknowns when preparing the cost estimate and

includes contingency to cover these costs. A 20% contingency was included on the direct costs in the estimates prepared as part of this study to cover unknowns.

36. Scrap value of steel is included at $320 per gross-ton.
37. Scrap value of copper is included at $2.89 per pound.
38. The current scrap metal values utilized in this study are on the higher end of the range relative to historical scrap metal pricing.
39. Pricing for all estimates is in 2011 dollars.
40. Market conditions may result in cost variations at the time of contract execution.

3.2 SITE SPECIFIC DECOMMISSIONING ASSUMPTIONS

3.2.1 Cape Fear

The following assumptions were made specific to the Cape Fear plant.

1. Boilers 1 – 6 and steam turbines 1 & 2 have had all asbestos abated, with the exception of the masonry boiler walls, which still remain. It is assumed that this masonry material contains asbestos and is contaminated with arsenic. All of this material will be handled as hazardous and will be disposed of in an approved hazardous waste landfill.
2. Boilers 7 & 8 and steam turbines 3 & 4 have had all asbestos abated.
3. Boilers 9 & 10 and associated steam turbines have been assumed to have had approximately 0% of the asbestos removed from the boilers, 0% of asbestos removed from the steam turbines, and 0% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
4. Unit 1 – 6 coal bunkers have been previously removed.
5. Unit 1 – 6 stacks have been previously removed.
6. The remaining concrete stacks are assumed to contain asbestos
7. The combustion turbines and HRSGs are assumed to contain asbestos insulation
8. In areas where fuel oil tanks have leaked, the affected areas will be excavated down 5 feet below the existing ground surface level. This soil will be hauled off and disposed of in an appropriately licensed landfill. For purposes of this study, this depth of removal from the surface was selected as an assumed average depth of removal for the contaminated areas. The actual contamination depth may be shallower or deeper in some areas, but for purposes of this study, this average removal depth was assumed. During final decommissioning activities, soil sampling will be performed if needed, to verify removal of contaminated material.

9. In areas where fuel oil pipes have leaked, a trench will be excavated 5 feet wide by 10 feet below the existing ground surface level. This soil will be hauled off and disposed of in an appropriately licensed landfill. For purposes of this study, this depth and of removal from the surface and width of removal was selected as an assumed average area of contamination surrounding the fuel oil lines. The actual area of contamination may be smaller or larger in some areas, but for purposes of this study, this average removal area was assumed. During final decommissioning activities, soil sampling will be performed if needed, to verify removal of contaminated material.
10. The discharge canal will be filled in by grading the berms around the site into the canal.
11. The older ash ponds that are no longer in use have not been capped. The cost of capping these ponds is included in the decommissioning costs.
12. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. PCB testing results were provided to BMcD by Progress Energy. All recent tests indicate that PCB levels are below 50 ppm. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 5 ppm and 50 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.2 Lee

The following assumptions were made specific to the Lee plant.

1. Estimated asbestos quantities were provided to BMcD by Progress Energy for transite paneling, boiler insulation, duct work, galbestos, and piping insulation. These quantities were applied to the estimates on a per unit basis, and the removal and disposal costs are included in the decommissioning estimate.
2. The cooling lake will remain as-is. The discharge canal will be filled in.
3. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. PCB testing results were provided to BMcD by Progress Energy. All recent tests indicate that PCB levels are below 50 ppm. For purposes of this study, it will be assumed that PCB levels of the transformer oils are between 5 ppm and 50 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained

PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.3 Sutton

The following assumptions were made specific to the Sutton plant.

1. Unit 1 - has been assumed to have had approximately 30% of the asbestos removed from the boilers, 30% of asbestos removed from the steam turbines, and 30% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
2. Unit 2 - has been assumed to have had 70% of the asbestos removed from the boilers, 30% of asbestos removed from the steam turbines, and 30% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
3. Unit 3 - has been assumed to have had approximately 100% of the asbestos removed from the boilers, 30% of asbestos removed from the steam turbines, and 30% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
4. The stacks are assumed to contain asbestos
5. The combustion turbines are assumed to contain asbestos insulation
6. The cooling lake will remain as-is.
7. An old asbestos burial pit has been capped with asphalt. It will be abandoned as-is.
8. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. PCB testing results were provided to BMcD by Progress Energy. All recent tests indicate that PCB levels are below 50 ppm. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 5 ppm and 50 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.4 Weatherspoon

The following assumptions were made specific to the Weatherspoon plant.

1. Asbestos quantities were provided to BMcD by Progress.

2. The cooling lake will require dredging of ash from a one-acre area approximately six feet thick ash prior to abandoning the lake.
3. In areas where fuel oil tanks have leaked, the affected areas will be excavated down 5 feet below the existing ground surface level. This soil will be hauled off and disposed of in an appropriately licensed landfill. For purposes of this study, this depth of removal from the surface was selected as an assumed average depth of removal for the contaminated areas. The actual contamination depth may be shallower or deeper in some areas, but for purposes of this study, this average removal depth was assumed. During final decommissioning activities, soil sampling will be performed if needed, to verify removal of contaminated material.
4. In areas where fuel oil pipes have leaked, a trench will be excavated 5 feet wide by 10 feet below the existing ground surface level. This soil will be hauled off and disposed of in an appropriately licensed landfill. For purposes of this study, this depth and of removal from the surface and width of removal was selected as an assumed average area of contamination surrounding the fuel oil lines. The actual area of contamination may be smaller or larger in some areas, but for purposes of this study, this average removal area was assumed. During final decommissioning activities, soil sampling will be performed if needed, to verify removal of contaminated material.
5. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. PCB testing results were provided to BMcD by Progress Energy. All recent tests indicate that PCB levels are below 50 ppm. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 5 ppm and 50 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.3 RESULTS

BMcD has prepared estimates in current dollars (2011$) for the decommissioning of the Plants. These costs are summarized in Table 3-1. A breakdown of the decommissioning costs can be found in Appendix A.

Table 3-1: Decommissioning Cost Summary

Asset	Decommissioning Costs	Credits	Net Project Cost
Cape Fear	$62,571,000	($11,608,000)	$50,963,000
Lee	$76,963,000	($9,410,000)	$67,553,000
Sutton	$53,465,000	($10,070,000)	$43,395,000
Weatherspoon	$26,806,000	($4,806,000)	$22,000,000

* * * * *

SECTION 4

LIMITATIONS

4.0 LIMITATIONS

In preparation of this decommissioning study, BMcD has relied upon information provided by Progress Energy. BMcD acknowledges that it has requested the information from Progress Energy that it deemed necessary to complete this study. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of decommissioning costs are based on Engineer's experience, qualifications and judgment. Since Engineer has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Engineer does not guarantee the accuracy of its estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

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APPENDIX A

DECOMMISSOINING COST BREAKDOWNS

Table A-1
Cape Fear Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Cape Fear Plant						
Unit 1 (Boilers 1 - 3)						
Asbestos Removal	$ -	$ -	$ -	$ 196,000	$ 196,000	$ -
Boiler	$ 184,000	$ 296,000	$ -	$ -	$ 480,000	$ -
Steam Turbine & Building	$ 130,000	$ 120,000	$ -	$ -	$ 250,000	$ -
GSU & Foundation	$ 16,000	$ 24,000	$ -	$ -	$ 40,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 2,253,000	$ -	$ 2,253,000	$ -
Debris	$ -	$ -	$ 50,000	$ -	$ 50,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,258,000)
Subtotal	**$ 330,000**	**$ 440,000**	**$ 2,303,000**	**$ 204,000**	**$ 3,277,000**	**$ (1,258,000)**
Unit 2 (Boilers 4 - 6)						
Asbestos Removal	$ -	$ -	$ -	$ 198,000	$ 198,000	$ -
Boiler	$ 188,000	$ 299,000	$ -	$ -	$ 487,000	$ -
Steam Turbine & Building	$ 15,000	$ 138,000	$ -	$ -	$ 153,000	$ -
GSU & Foundation	$ 18,000	$ 24,000	$ -	$ -	$ 42,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 2,276,000	$ -	$ 2,276,000	$ -
Debris	$ -	$ -	$ 50,000	$ -	$ 50,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,334,000)
Subtotal	**$ 221,000**	**$ 461,000**	**$ 2,326,000**	**$ 206,000**	**$ 3,214,000**	**$ (1,334,000)**
Unit 3 (Boiler 7)						
Asbestos Removal	$ -	$ -	$ -	$ 66,000	$ 66,000	$ -
Boiler	$ 229,000	$ 232,000	$ -	$ -	$ 461,000	$ -
Steam Turbine & Building	$ 186,000	$ 172,000	$ -	$ -	$ 358,000	$ -
GSU & Foundation	$ 21,000	$ 30,000	$ -	$ -	$ 51,000	$ -
Hazardous Materials Disposal (Refractory)	$ 1,000	$ 1,000	$ -	$ -	$ 2,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,772,000	$ -	$ 1,772,000	$ -
Debris	$ -	$ -	$ 101,000	$ -	$ 101,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,513,000)
Subtotal	**$ 437,000**	**$ 435,000**	**$ 1,873,000**	**$ 66,000**	**$ 2,811,000**	**$ (1,513,000)**
Unit 4 (Boiler 8)						
Asbestos Removal	$ -	$ -	$ -	$ 73,000	$ 73,000	$ -
Boiler	$ 229,000	$ 232,000	$ -	$ -	$ 461,000	$ -
Steam Turbine & Building	$ 186,000	$ 172,000	$ -	$ -	$ 358,000	$ -
GSU & Foundation	$ 21,000	$ 30,000	$ -	$ -	$ 51,000	$ -
Hazardous Materials Disposal (Refractory)	$ 1,000	$ 1,000	$ -	$ -	$ 2,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,653,000	$ -	$ 1,653,000	$ -
Debris	$ -	$ -	$ 101,000	$ -	$ 101,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,511,000)
Subtotal	**$ 437,000**	**$ 435,000**	**$ 1,754,000**	**$ 73,000**	**$ 2,699,000**	**$ (1,511,000)**
Unit 5 (Boiler 9)						
Asbestos Removal	$ -	$ -	$ -	$ 866,000	$ 866,000	$ -
Boiler	$ 874,000	$ 796,000	$ -	$ -	$ 1,670,000	$ -
Steam Turbine & Building	$ 669,000	$ 620,000	$ -	$ -	$ 1,289,000	$ -
Precipitator	$ 75,000	$ 80,000	$ -	$ -	$ 155,000	$ -
Stack	$ 223,000	$ 480,000	$ -	$ -	$ 703,000	$ -
GSU & Foundation	$ 37,000	$ 53,000	$ -	$ -	$ 90,000	$ -
Hazardous Materials Disposal (Refractory)	$ 2,000	$ 3,000	$ -	$ -	$ 5,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,088,000	$ -	$ 1,088,000	$ -
Debris	$ -	$ -	$ 278,000	$ -	$ 278,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,435,000)
Subtotal	**$ 1,880,000**	**$ 2,032,000**	**$ 1,366,000**	**$ 866,000**	**$ 6,144,000**	**$ (2,435,000)**
Unit 6 (Boiler 10)						
Asbestos Removal	$ -	$ -	$ -	$ 734,000	$ 734,000	$ -
Boiler	$ 699,000	$ 657,000	$ -	$ -	$ 1,356,000	$ -
Steam Turbine & Building	$ 539,000	$ 49,000	$ -	$ -	$ 588,000	$ -
Precipitator	$ 70,000	$ 66,000	$ -	$ -	$ 136,000	$ -
Stack	$ 223,000	$ 480,000	$ -	$ -	$ 703,000	$ -
GSU & Foundation	$ 41,000	$ 59,000	$ -	$ -	$ 100,000	$ -
Hazardous Materials Disposal (Refractory)	$ 2,000	$ 2,000	$ -	$ -	$ 4,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 593,000	$ -	$ 593,000	$ -
Debris	$ -	$ -	$ 219,000	$ -	$ 219,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,707,000)
Subtotal	**$ 1,574,000**	**$ 1,313,000**	**$ 812,000**	**$ 734,000**	**$ 4,433,000**	**$ (2,707,000)**
Material Handling Facilities						
Demolition	$ 99,000	$ 110,000	$ -	$ -	$ 209,000	$ -
Coal Storage Area Restoration	$ -	$ -	$ -	$ 988,000	$ 988,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Debris	$ -	$ -	$ 25,000	$ -	$ 25,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (31,000)
Subtotal	**$ 99,000**	**$ 110,000**	**$ 26,000**	**$ 988,000**	**$ 1,223,000**	**$ (31,000)**

Combined Cycle Unit 1						
Turbines & Foundations	$ 107,000	$ 80,000	$ -	$ -	$ 187,000	$ -
GSUs	$ 13,000	$ 10,000	$ -	$ -	$ 23,000	$ -
Onsite Crush Conrete and Disposal	$ 5,000	$ -	$ -	$ -	$ 5,000	$ -
Debris	$ 1,000	$ -	$ -	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (239,000)
Subtotal	**$ 126,000**	**$ 90,000**	**$ -**	**$ -**	**$ 216,000**	**$ (239,000)**
Combined Cycle Unit 2						
Turbines & Foundations	$ 107,000	$ 80,000	$ -	$ -	$ 187,000	$ -
GSUs	$ 13,000	$ 10,000	$ -	$ -	$ 23,000	$ -
Onsite Crush Conrete and Disposal	$ 5,000	$ -	$ -	$ -	$ 5,000	$ -
Debris	$ 1,000	$ -	$ -	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (239,000)
Subtotal	**$ 126,000**	**$ 90,000**	**$ -**	**$ -**	**$ 216,000**	**$ (239,000)**
Common Facilities						
Cooling Water Intakes and Circulating Water Pumps	$ 82,000	$ 110,000	$ -	$ -	$ 192,000	$ -
Cooling Water Discharge Canal	$ 33,000	$ 183,000	$ -	$ 117,000	$ 333,000	$ -
Cooling Tower	$ 48,000	$ 235,000	$ -	$ 180,000	$ 463,000	$ -
All BOP Buildings	$ 41,000	$ 15,000	$ -	$ -	$ 56,000	$ -
Closure of Ash Ponds	$ -	$ -	$ -	$ 22,000,000	$ 22,000,000	$ -
Fuel Oil Storage Tanks	$ 31,000	$ 44,000	$ -	$ -	$ 75,000	$ -
All Other Tanks	$ 16,000	$ 14,000	$ -	$ -	$ 30,000	$ -
Remediation of Soil Impacted by Fuel Oil Leak	$ -	$ -	$ -	$ 1,005,000	$ 1,005,000	$ -
PCB Oil Transportation and Disposal (>5 ppm to <50 ppm)	$ -	$ -	$ -	$ 131,000	$ 131,000	$ -
Soil Removal Beneath for PCB Equipment	$ -	$ -	$ -	$ 766,000	$ 766,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 230,000	$ 230,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 45,000	$ 45,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ 4,000	$ -	$ 4,000	$ -
Plant Washdown & Materials Disposal	$ -	$ -	$ 483,000	$ -	$ 483,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ -	$ -	$ -	$ (341,000)
Subtotal	**$ 251,000**	**$ 601,000**	**$ 487,000**	**$ 24,485,000**	**$ 25,824,000**	**$ (341,000)**
Cape Fear Plant Subtotal	**$ 5,481,000**	**$ 6,007,000**	**$ 10,947,000**	**$ 27,622,000**	**$ 50,057,000**	**$ (11,608,000)**
TOTAL COST (CREDIT)					**$ 50,057,000**	**$ (11,608,000)**
PROJECT INDIRECTS (5%)					**$ 2,503,000**	
CONTINGENGY (20%)					**$ 10,011,000**	
TOTAL PROJECT COST (CREDIT)					**$ 62,571,000**	**$ (11,608,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 50,963,000**	

Table A-2
Lee Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Lee Plant						
Unit 1						
Asbestos Removal	$ -	$ -	$ -	$ 819,000	$ 819,000	$ -
Boiler	$ 405,000	$ 396,000	$ -	$ -	$ 801,000	$ -
Steam Turbine & Building	$ 467,000	$ 424,000	$ -	$ -	$ 891,000	$ -
Precipitator	$ 40,000	$ 40,000	$ -	$ -	$ 80,000	$ -
Stack - Common Unit 1 & 2	$ 143,000	$ 366,000	$ -	$ -	$ 509,000	$ -
GSU & Foundation	$ 29,000	$ 42,000	$ -	$ -	$ 71,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 385,000	$ -	$ 385,000	$ -
Debris	$ -	$ -	$ 158,000	$ -	$ 158,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,554,000)
Subtotal	**$ 1,084,000**	**$ 1,268,000**	**$ 543,000**	**$ 827,000**	**$ 3,722,000**	**$ (1,554,000)**
Unit 2						
Asbestos Removal	$ -	$ -	$ -	$ 775,000	$ 775,000	$ -
Boiler	$ 345,000	$ 345,000	$ -	$ -	$ 690,000	$ -
Steam Turbine & Building	$ 403,000	$ 366,000	$ -	$ -	$ 769,000	$ -
Precipitator	$ 34,000	$ 34,000	$ -	$ -	$ 68,000	$ -
GSU & Foundation	$ 28,000	$ 41,000	$ -	$ -	$ 69,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 631,000	$ -	$ 631,000	$ -
Debris	$ -	$ -	$ 150,000	$ -	$ 150,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,614,000)
Subtotal	**$ 810,000**	**$ 786,000**	**$ 781,000**	**$ 783,000**	**$ 3,160,000**	**$ (1,614,000)**
Unit 3						
Asbestos Removal	$ -	$ -	$ -	$ 3,101,000	$ 3,101,000	$ -
Boiler	$ 1,075,000	$ 525,000	$ -	$ -	$ 1,600,000	$ -
Steam Turbine & Building	$ 1,253,000	$ 200,000	$ -	$ -	$ 1,453,000	$ -
Precipitator	$ 108,000	$ 53,000	$ -	$ -	$ 161,000	$ -
Stack	$ 143,000	$ 386,000	$ -	$ -	$ 529,000	$ -
GSU & Foundation	$ 49,000	$ 75,000	$ -	$ -	$ 124,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 699,000	$ -	$ 699,000	$ -
Debris	$ -	$ -	$ 600,000	$ -	$ 600,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (4,680,000)
Subtotal	**$ 2,628,000**	**$ 1,239,000**	**$ 1,299,000**	**$ 3,109,000**	**$ 8,275,000**	**$ (4,680,000)**
Coal Handling Facilities						
Demolition	$ 99,000	$ 114,000	$ -	$ -	$ 213,000	$ -
Coal Storage Area Restoration	$ -	$ -	$ -	$ 1,547,000	$ 1,547,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Debris	$ -	$ -	$ 30,000	$ -	$ 30,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (29,000)
Subtotal	**$ 99,000**	**$ 114,000**	**$ 31,000**	**$ 1,547,000**	**$ 1,791,000**	**$ (29,000)**
Combustion Turbine Unit 1						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ 3,000	$ 2,000	$ -	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (390,000)
Subtotal	**$ 40,000**	**$ 30,000**	**$ -**	**$ -**	**$ 70,000**	**$ (390,000)**
Combustion Turbine Unit 2						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ 4,000	$ 3,000	$ -	$ -	$ 7,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (368,000)
Subtotal	**$ 41,000**	**$ 31,000**	**$ -**	**$ -**	**$ 72,000**	**$ (368,000)**
Combustion Turbine Unit 3						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ 7,000	$ 5,000	$ -	$ -	$ 12,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (364,000)
Subtotal	**$ 44,000**	**$ 33,000**	**$ -**	**$ -**	**$ 77,000**	**$ (364,000)**
Combustion Turbine Unit 4						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ 7,000	$ 5,000	$ -	$ -	$ 12,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (155,000)
Subtotal	**$ 44,000**	**$ 33,000**	**$ -**	**$ -**	**$ 77,000**	**$ (155,000)**

Common Facilities						
Cooling Water System and Circulating Water Pumps	$ 85,000	$ 17,000	$ -	$ -	$ 102,000	$ -
Cooling Tower and Basin	$ 34,000	$ 11,000	$ -	$ -	$ 45,000	$ -
All BOP Buildings	$ 42,000	$ 15,000	$ -	$ -	$ 57,000	$ -
Closure of Ash Ponds	$ -	$ -	$ -	$ 43,000,000	$ 43,000,000	$ -
Fuel Oil Storage Tanks	$ 20,000	$ 145,000	$ -	$ -	$ 165,000	$ -
All Other Tanks	$ 17,000	$ 14,000	$ -	$ -	$ 31,000	$ -
PCB Oil Transportation and Disposal (>5 ppm to <50 ppm)	$ -	$ -	$ -	$ 105,000	$ 105,000	$ -
Soil Removal Beneath for PCB Equipment	$ -	$ -	$ -	$ 442,000	$ 442,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 160,000	$ 160,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 10,000	$ 10,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Plant Washdown & Materials Disposal	$ -	$ -	$ 110,000	$ 69,000	$ 179,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 7,000	$ -	$ 7,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (256,000)
Subtotal	**$ 198,000**	**$ 202,000**	**$ 118,000**	**$ 43,808,000**	**$ 44,326,000**	**$ (256,000)**
Lee Plant Subtotal	**$ 4,988,000**	**$ 3,736,000**	**$ 2,772,000**	**$ 50,074,000**	**$ 61,570,000**	**$ (9,410,000)**
TOTAL COST (CREDIT)					**$ 61,570,000**	**$ (9,410,000)**
PROJECT INDIRECTS (5%)					**$ 3,079,000**	
CONTINGENGY (20%)					**$ 12,314,000**	
TOTAL PROJECT COST (CREDIT)					**$ 76,963,000**	**$ (9,410,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 67,553,000**	

Table A-3
Sutton Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Sutton Plant						
Unit 1						
Asbestos Removal	$ -	$ -	$ -	$ 831,000	$ 831,000	$ -
Boiler	$ 277,000	$ 257,000	$ -	$ -	$ 534,000	$ -
Steam Turbine & Building	$ 235,000	$ 220,000	$ -	$ -	$ 455,000	$ -
Precipitator	$ 24,000	$ 26,000	$ -	$ -	$ 50,000	$ -
Stack - Common Unit 1 & 2	$ 387,000	$ 1,006,000	$ -	$ -	$ 1,393,000	$ -
GSU & Foundation	$ 47,000	$ 73,000	$ -	$ -	$ 120,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 497,000	$ -	$ 497,000	$ -
Debris	$ -	$ -	$ 396,000	$ -	$ 396,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,996,000)
Subtotal	**$ 970,000**	**$ 1,582,000**	**$ 893,000**	**$ 839,000**	**$ 4,284,000**	**$ (1,996,000)**
Unit 2						
Asbestos Removal	$ -	$ -	$ -	$ 356,000	$ 356,000	$ -
Boiler	$ 277,000	$ 257,000	$ -	$ -	$ 534,000	$ -
Steam Turbine & Building	$ 235,000	$ 220,000	$ -	$ -	$ 455,000	$ -
Precipitator	$ 24,000	$ 26,000	$ -	$ -	$ 50,000	$ -
GSU & Foundation	$ 47,000	$ 73,000	$ -	$ -	$ 120,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 545,000	$ -	$ 545,000	$ -
Debris	$ -	$ -	$ 396,000	$ -	$ 396,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,969,000)
Subtotal	**$ 583,000**	**$ 576,000**	**$ 941,000**	**$ 364,000**	**$ 2,464,000**	**$ (1,969,000)**
Unit 3						
Asbestos Removal	$ -	$ -	$ -	$ 209,000	$ 209,000	$ -
Boiler	$ 1,254,000	$ 941,000	$ -	$ -	$ 2,195,000	$ -
Steam Turbine & Building	$ 995,000	$ 929,000	$ -	$ -	$ 1,924,000	$ -
Precipitator	$ 125,000	$ 94,000	$ -	$ -	$ 219,000	$ -
Stack	$ 387,000	$ 1,006,000	$ -	$ -	$ 1,393,000	$ -
GSU & Foundation	$ 97,000	$ 143,000	$ -	$ -	$ 240,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,408,000	$ -	$ 1,408,000	$ -
Debris	$ -	$ -	$ 1,792,000	$ -	$ 1,792,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,597,000)
Subtotal	**$ 2,858,000**	**$ 3,113,000**	**$ 3,200,000**	**$ 217,000**	**$ 9,388,000**	**$ (5,597,000)**
Material Handling Facilities						
Demolition	$ 113,000	$ 194,000	$ -	$ -	$ 307,000	$ -
Coal Storage Area Restoration	$ -	$ -	$ -	$ 2,544,000	$ 2,544,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Debris	$ -	$ -	$ 60,000	$ -	$ 60,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (34,000)
Subtotal	**$ 113,000**	**$ 194,000**	**$ 61,000**	**$ 2,544,000**	**$ 2,912,000**	**$ (34,000)**
Combustion Turbine Unit 1						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ 3,000	$ 2,000	$ -	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (88,000)
Subtotal	**$ 40,000**	**$ 30,000**	**-**	**$ -**	**$ 70,000**	**$ (88,000)**
Combustion Turbine Unit 2						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ 5,000	$ 3,000	$ -	$ -	$ 8,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (88,000)
Subtotal	**$ 42,000**	**$ 31,000**	**-**	**$ -**	**$ 73,000**	**$ (88,000)**
Combustion Turbine Unit 3						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ 5,000	$ 3,000	$ -	$ -	$ 8,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (88,000)
Subtotal	**$ 42,000**	**$ 31,000**	**-**	**$ -**	**$ 73,000**	**$ (88,000)**

Common Facilities						
Cooling Water Intakes and Circulating Water Pumps	$ 145,000	$ 29,000	$ -	$ -	$ 174,000	$ -
Cooling Water Discharge Canal	$ 58,000	$ 19,000	$ -	$ -	$ 77,000	$ -
All BOP Buildings	$ 72,000	$ 26,000	$ -	$ -	$ 98,000	$ -
Closure of Ash Ponds	$ -	$ -	$ -	$ 21,000,000	$ 21,000,000	$ -
Fuel Oil Storage Tanks	$ 54,000	$ 78,000	$ -	$ -	$ 132,000	$ -
All Other Tanks	$ 29,000	$ 25,000	$ -	$ -	$ 54,000	$ -
PCB Oil Transportation and Disposal (>5 ppm to <50 ppm)	$ -	$ -	$ -	$ 87,000	$ 87,000	$ -
Soil Removal Beneath for PCB Equipment	$ -	$ -	$ -	$ 412,000	$ 412,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 1,346,000	$ 1,346,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 23,000	$ 23,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Plant Washdown & Materials Disposal	$ -	$ -	$ -	$ 69,000	$ 69,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 9,000	$ -	$ 9,000	$ -
Debris	$ -	$ -	$ 8,000	$ -	$ 8,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (210,000)
Subtotal	**$ 358,000**	**$ 177,000**	**$ 17,000**	**$ 22,956,000**	**$ 23,508,000**	**$ (210,000)**
Sutton Plant Subtotal	**$ 5,006,000**	**$ 5,734,000**	**$ 5,112,000**	**$ 26,920,000**	**$ 42,772,000**	**$ (10,070,000)**
TOTAL COST (CREDIT)					**$ 42,772,000**	**$ (10,070,000)**
PROJECT INDIRECTS (5%)					**$ 2,139,000**	
CONTINGENGY (20%)					**$ 8,554,000**	
TOTAL PROJECT COST (CREDIT)					**$ 53,465,000**	**$ (10,070,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 43,395,000**	

Table A-4
Weatherspoon Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Weatherspoon Plant						
Unit 1						
Asbestos Removal	$ -	$ -	$ -	$ 526,000	$ 526,000	$ -
Boiler	$ 270,000	$ 248,000	$ -	$ -	$ 518,000	$ -
Steam Turbine & Building	$ 251,000	$ 203,000	$ -	$ -	$ 454,000	$ -
Precipitator	$ 27,000	$ 25,000	$ -	$ -	$ 52,000	$ -
Stack - Common Unit 1 & 2	$ 105,000	$ 297,000	$ -	$ -	$ 402,000	$ -
GSU & Foundation	$ 33,000	$ 48,000	$ -	$ -	$ 81,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 197,000	$ -	$ 197,000	$ -
Debris	$ -	$ -	$ 113,000	$ -	$ 113,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,017,000)
Subtotal	**$ 686,000**	**$ 821,000**	**$ 310,000**	**$ 534,000**	**$ 2,351,000**	**$ (1,017,000)**
Unit 2						
Asbestos Removal	$ -	$ -	$ -	$ 526,000	$ 526,000	$ -
Boiler	$ 270,000	$ 248,000	$ -	$ -	$ 518,000	$ -
Steam Turbine & Building	$ 251,000	$ 203,000	$ -	$ -	$ 454,000	$ -
Precipitator	$ 27,000	$ 25,000	$ -	$ -	$ 52,000	$ -
GSU & Foundation	$ 33,000	$ 48,000	$ -	$ -	$ 81,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 216,000	$ -	$ 216,000	$ -
Debris	$ -	$ -	$ 113,000	$ -	$ 113,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,004,000)
Subtotal	**$ 581,000**	**$ 524,000**	**$ 329,000**	**$ 534,000**	**$ 1,968,000**	**$ (1,004,000)**
Unit 3						
Asbestos Removal	$ -	$ -	$ -	$ 748,000	$ 748,000	$ -
Boiler	$ 410,000	$ 351,000	$ -	$ -	$ 761,000	$ -
Steam Turbine & Building	$ 394,000	$ 308,000	$ -	$ -	$ 702,000	$ -
Precipitator	$ 41,000	$ 4,000	$ -	$ -	$ 45,000	$ -
Stack	$ 105,000	$ 297,000	$ -	$ -	$ 402,000	$ -
GSU & Foundation	$ 34,000	$ 49,000	$ -	$ -	$ 83,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 721,000	$ -	$ 721,000	$ -
Debris	$ -	$ -	$ 160,000	$ -	$ 160,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,834,000)
Subtotal	**$ 984,000**	**$ 1,009,000**	**$ 881,000**	**$ 756,000**	**$ 3,630,000**	**$ (1,834,000)**
Material Handling Facilities						
Demolition	$ 144,000	$ 94,000	$ -	$ -	$ 238,000	$ -
Coal Storage Area Restoration	$ -	$ -	$ -	$ 1,260,000	$ 1,260,000	$ -
Debris	$ -	$ -	$ 19,000	$ -	$ 19,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (35,000)
Subtotal	**$ 144,000**	**$ 94,000**	**$ 19,000**	**$ 1,260,000**	**$ 1,517,000**	**$ (35,000)**
Combustion Turbine Unit 1						
Turbines & Foundations	$ 61,000	$ 46,000	$ -	$ -	$ 107,000	$ -
GSUs	$ 20,000	$ 15,000	$ -	$ -	$ 35,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (144,000)
Subtotal	**$ 81,000**	**$ 61,000**	**$ 1,000**	**$ -**	**$ 143,000**	**$ (144,000)**
Combustion Turbine Unit 2						
Turbines & Foundations	$ 61,000	$ 46,000	$ -	$ -	$ 107,000	$ -
GSUs	$ 20,000	$ 15,000	$ -	$ -	$ 35,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (144,000)
Subtotal	**$ 81,000**	**$ 61,000**	**$ 1,000**	**$ -**	**$ 143,000**	**$ (144,000)**
Combustion Turbine Unit 3						
Turbines & Foundations	$ 61,000	$ 46,000	$ -	$ -	$ 107,000	$ -
GSUs	$ 20,000	$ 15,000	$ -	$ -	$ 35,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (144,000)
Subtotal	**$ 81,000**	**$ 61,000**	**$ 1,000**	**$ -**	**$ 143,000**	**$ (144,000)**

Combustion Turbine Unit 4						
Turbines & Foundations	$ 61,000	$ 46,000	$ -	$ -	$ 107,000	$ -
GSUs	$ 20,000	$ 15,000	$ -	$ -	$ 35,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (218,000)
Subtotal	**$ 81,000**	**$ 61,000**	**$ 1,000**	**$ -**	**$ 143,000**	**$ (218,000)**
Common Facilities						
Cooling Water Intakes and Circulating Water Pumps	$ 100,000	$ 159,000	$ -	$ -	$ 259,000	$ -
Cooling Water Discharge Canal	$ 45,000	$ 88,000	$ -	$ -	$ 133,000	$ -
All BOP Buildings	$ 17,000	$ 6,000	$ -	$ -	$ 23,000	$ -
Closure of Ash Pond	$ -	$ -	$ -	$ 7,000,000	$ 7,000,000	$ -
All Other Tanks	$ 20,000	$ 78,000	$ -	$ -	$ 98,000	$ -
Remediation of Soil Impacted by Fuel Oil Leak	$ -	$ -	$ -	$ 2,779,000	$ 2,779,000	$ -
PCB Oil Transportation and Disposal (>5 ppm to <50 ppm)	$ -	$ -	$ -	$ 56,000	$ 56,000	$ -
Soil Removal Beneath for PCB Equipment	$ -	$ -	$ -	$ 324,000	$ 324,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 129,000	$ 129,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 23,000	$ 23,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Plant Washdown & Materials Disposal	$ -	$ -	$ -	$ 69,000	$ 69,000	$ -
Fly Ash Removal from Cooling Pond	$ -	$ -	$ -	$ 484,000	$ 484,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 8,000	$ -	$ 8,000	$ -
Debris	$ -	$ -	$ 3,000	$ -	$ 3,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (266,000)
Subtotal	**$ 182,000**	**$ 331,000**	**$ 11,000**	**$ 10,883,000**	**$ 11,407,000**	**$ (266,000)**
Weatherspoon Plant Subtotal	**$ 2,901,000**	**$ 3,023,000**	**$ 1,554,000**	**$ 13,967,000**	**$ 21,445,000**	**$ (4,806,000)**
TOTAL COST (CREDIT)					**$ 21,445,000**	**$ (4,806,000)**
PROJECT INDIRECTS (5%)					**$ 1,072,000**	
CONTINGENGY (20%)					**$ 4,289,000**	
TOTAL PROJECT COST (CREDIT)					**$ 26,806,000**	**$ (4,806,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 22,000,000**	

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Burns & McDonnell: Making our clients successful for more than 100 years

2012 Near Term Decommissioning Study for Robinson

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Report on the

Decommissioning Cost Study Future Units to be Decommissioned

Progress Energy Carolinas

Project No. 62009

January 2012

Burns & McDonnell
SINCE 1898

January 27, 2012

Mr. Issa Zarzar
Manager – Plant Decommissioning Projects
Progress Energy, Inc.
410 South Wilmington Street
Raleigh, North Carolina 27601

Re: Decommissioning Cost Study
BMcD Project No. 62009

Dear Mr. Zarzar:

Burns & McDonnell (BMcD) is pleased to submit this Decommissioning Cost Study prepared on behalf of Progress Energy Carolinas (Progress).

BMcD was retained by Progress to conduct a Decommissioning Cost Study (Study) for power generation assets in North Carolina and South Carolina, excluding nuclear units. The assets include natural gas, fuel oil, hydro-electric, and coal-fired generating facilities. Individuals from BMcD visited each of the Plants covered by the Study in July of 2011, along with a representative from LVI Services (LVI), a demolition contractor who is serving as a sub-consultant to BMcD on the Study. The purpose of the Study was to review the facilities and to make a recommendation to Progress regarding the total cost to decommission the facilities at the end of their useful lives.

The attached report presents the results of the Study, along with the cost estimates for decommissioning each of the facilities. The included costs are presented in 2011 dollars.

If you need any additional information, please contact me at (816) 822-4239 or jkopp@burnsmcd.com. It is a pleasure to be of service to Progress in this matter.

Sincerely,

Jeffrey T Kopp

Jeff Kopp, PE
Project Manager

cc: Vic Ranalletta, PE - BMcD
Jeff Pope, PE - BMcD
Michael Marcheschi - LVI

Decommissioning Cost Study

prepared for

Progress Energy Carolinas
Raleigh, North Carolina

January 2012

Project No. 62009

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF APPENDICES

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EXECUTIVE SUMMARY

ES.0 EXECUTIVE SUMMARY

ES.1 INTRODUCTION

Burns & McDonnell (BMcD) was retained by Progress Energy Carolinas (Progress) to conduct a Decommissioning Cost Study (Study) for power generation assets (Plants) in North Carolina and South Carolina, excluding nuclear units. The assets include natural gas, fuel oil, hydro-electric, and coal-fired generating facilities. Individuals from BMcD visited each of the Plants covered by the Study in July of 2011, along with a representative from LVI Services (LVI), a demolition contractor who is serving as a sub-consultant to BMcD on the Study. The purpose of the Study was to review the facilities and to make a recommendation to Progress regarding the total cost to decommission the facilities at the end of their useful lives.

The decommissioning costs were developed using the information provided by Progress, in-house data available to BMcD, and information supplied by LVI. Quantity take-offs were performed for major plant facilities and equipment based on observations from the site visits and review of drawings provided for each Plant. Decommissioning activities were determined and labor hours were estimated to complete each decommissioning activity. Current market pricing for labor rates and unit pricing were then developed for each task, and these rates were applied to the estimated quantities for the Plants to determine the total cost of decommissioning.

ES.2 RESULTS

BMcD has prepared estimates in current dollars (2011$) for the decommissioning of the Plants. These costs are summarized in Table ES-1. When Progress determines that the Plants should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the decommissioning costs. Progress will incur costs in the demolition and restoration of the sites less the salvage value of equipment and bulk steel.

Table ES-1: Decommissioning Cost Summary

Asset	Decommissioning Costs	Credits	Net Project Cost
Asheville	$33,757,000	($9,039,000)	$24,718,000
Blewett	$6,894,000	($1,090,000)	$5,804,000
Darlington	$6,348,000	($5,127,000)	$1,221,000
Marshall	$1,626,000	($179,000)	$1,447,000
Mayo	$54,296,000	($11,826,000)	$42,470,000
Morehead City	$186,000	($137,000)	$49,000
Richmond	$14,618,000	($11,138,000)	$3,480,000
Robinson	$23,938,000	($2,814,000)	$21,124,000
Roxboro	$154,870,000	($23,403,000)	$131,467,000
Tillery	$5,105,000	($1,444,000)	$3,661,000
Walters	$2,005,000	($1,391,000)	$614,000
Wayne	$2,654,000	($3,675,000)	($1,021,000)

The total project costs presented above include the costs to return the sites to an industrial condition suitable for reuse for development of an industrial facility. Included are the costs to dismantle the power generating equipment owned by Progress as well as the costs to dismantle the Progress owned balance of plant facilities and environmental site restoration activities.

ES.3 STATEMENT OF LIMITATIONS

In preparation of this decommissioning study, BMcD has relied upon information provided by Progress Energy. BMcD acknowledges that it has requested the information from Progress Energy that it deemed necessary to complete this study. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of decommissioning costs are based on Engineer's experience, qualifications and judgment. Since Engineer has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Engineer does not guarantee the accuracy of its estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

* * * * *

SECTION 1
INTRODUCTION

1.0 INTRODUCTION

1.1 BACKGROUND

Burns & McDonnell (BMcD) was retained by Progress Energy Carolinas (Progress) to conduct a Decommissioning Cost Study (Study) for power generation assets (Plants) in North Carolina and South Carolina, excluding nuclear units. The assets include natural gas, fuel oil, hydro-electric, and coal-fired generating facilities. Individuals from BMcD visited each of the Plants covered by the Study in July of 2011, along with a representative from LVI Services (LVI), a demolition contractor who is serving as a sub-consultant to BMcD on the Study. The purpose of the Study was to review the facilities and to make a recommendation to Progress regarding the total cost to decommission the facilities at the end of their useful lives.

The decommissioning costs were developed using the information provided by Progress, in-house data available to BMcD, and information supplied by LVI. Quantity take-offs were performed for major plant facilities and equipment based on observations from the site visits and review of drawings provided for each Plant. Decommissioning activities were determined and labor hours were estimated to complete each decommissioning activity. Current market pricing for labor rates and unit pricing were then developed for each task, and these rates were applied to the estimated quantities for the Plants to determine the total cost of decommissioning.

1.2 STUDY METHODOLOGY

The site decommissioning costs were developed using information provided by Progress, information developed by LVI, and in-house data BMcD has collected from previous project experience. BMcD estimated quantities for equipment based on a visual inspection of the facilities, review of engineering drawings, BMcD’s in house database of plant equipment quantities, along with LVI and BMcD’s professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each decommissioning effort. Current market pricing for labor rates, equipment, and unit pricing were then developed for each task. The unit pricing was developed for each site based on the labor rates, equipment costs, and disposal costs specific to the area in which the work is to be performed. These rates were applied to the quantities for the Plants to determine the total cost of decommissioning for each site.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to decommission all of the assets owned by Progress at the site, including power generating equipment and balance of plant facilities

1.3 SITE VISITS

Representatives from BMcD and LVI visited the sites. The site visit consisted of a tour of the Facility with Plant personnel to review the equipment installed at the site. Tours were conducted by Plant personnel.

Mr. Paul Desai, from Progress Energy, served as the Progress representative throughout the site visits, along with plant personnel at each of the sites.

The following BMcD representatives comprised the site visit team:

- Mr. Jeff Kopp, Project Manager
- Mr. Vic Ranalletta, Lead Engineer
- Mr. Jeff Pope, Lead Environmental

In addition, Mr. Jeff Grubich, Environmental Specialist, filled in for Mr. Jeff Pope on several of the site visits. The site visits were performed on the following dates.

Table 1-1: Site Visit Dates

Asset	Site Visit Date
Asheville	July 27, 2011
Blewett	July 26, 2011
Darlington	July 25, 2011
Marshall	July 28, 2011
Mayo	July 19, 2011
Morehead City	July 22, 2011
Richmond	July 26, 2011
Robinson	July 25, 2011
Roxboro	July 19, 2011
Tillery	July 26, 2011
Walters	July 28, 2011
Wayne	July 20, 2011

* * * * *

SECTION 2

PLANT DESCRIPTIONS

2.0 PLANT DESCRIPTIONS

2.1 ASHEVILLE

The Asheville plant is located just south of Asheville, in Arden, North Carolina. The facility includes two coal-fired units rated at a total capacity of 376 megawatts. The units include electrostatic precipitators, and have been retrofitted with a common selective catalytic reduction (SCR) system and a common flue gas desulfurization (FGD) system. The plant site includes a cooling lake and several ash ponds. In addition to the coal-fired units, the plant includes two GE 7FA combustion turbines operating in simple cycle mode.

2.2 BLEWETT

The Blewett plant is located approximately 30 miles east of Charlotte, in Lilesville, North Carolina. The facility includes four GE Frame 5 combustion turbines operating in simple cycle mode. The units are fired on fuel oil only. The site also includes a six-unit hydro-electric plant, totaling 22 megawatts.

2.3 DARLINGTON

The Darlington plant is located approximately 30 miles northeast of Columbia, South Carolina. The plant includes a total of 16 simple cycle combustion turbines. The units include 6 Westinghouse 501AA combustion turbines, 5 Westinghouse 501AB combustion turbines, and 2 Westinghouse 501D5A combustion turbines. The plant includes a fuel oil unloading station, two 5 million gallon fuel oil tanks, and a 1 million gallon fuel oil tank. All of the units run on fuel oil, and 6 of the units can run on natural gas as well.

2.4 MARSHALL

The Marshall plant is located just north of Asheville, in Marshall, North Carolina. The facility consists of two hydro-electric units, totaling 4 megawatts.

2.5 MAYO

The Mayo plant is located near Roxboro, North Carolina. The facility includes a dual boiler unit with a rated capacity of 727 megawatts. The boilers include electrostatic precipitators, and have been retrofitted with a common selective catalytic reduction (SCR) system and a common flue gas desulfurization system (scrubber). The plant site includes a cooling lake and several ash ponds.

2.6 MOREHEAD CITY

The Morehead City plant is located in Morehead City, North Carolina. The facility consists of a single Westinghouse 191 IC combustion turbine operating in simple cycle mode.

2.7 RICHMOND

The Richmond plant is located approximately 40 miles east of Charlotte, in Hamlet, North Carolina. The facility includes five GE 7FA combustion turbines operating in simple cycle mode. The facility also includes a 2-on-1 combined cycle powerblock consisting of two GE 7FAcombustion turbines, two heat recovery steam generators, and a Toshiba steam turbine. A second combined cycle powerblock is located onsite, consisting of two Siemens SGT6-5000F combustion turbines, two heat recovery steam generators, and a GE steam turbine.

2.8 ROBINSON

The Robinson plant is located approximately 30 miles northeast of Columbia, South Carolina. The facility includes a single coal-fired unit and a single Westinghouse 191 IC combustion turbine operating in simple cycle mode. The units include electrostatic precipitators, but do not include SCR systems or FGD systems. The plant site includes a cooling lake and ash ponds. The plant is located on the same site as a Progress Energy owned nuclear generating station.

2.9 ROXBORO

The Roxboro plant is located near Roxboro, North Carolina. The facility consists of four coal-fired units totaling 2,422 megawatts. The units include electrostatic precipitators, and have all been retrofitted with SCR systems and FGD systems. The plant site includes a cooling lake and ash ponds.

2.10 TILLERY

The Tillery plant is located approximately 30 miles east of Charlotte, in Mt. Gilead, North Carolina. The facility consists of a four hydro-electric units, totaling 87 megawatts.

2.11 WALTERS

The Walters plant is located approximately 20 miles northwest of Asheville, in Waterville, North Carolina. The facility consists of a four hydro-electric units, totaling 112 megawatts.

2.12 WAYNE

The Wayne plant is located in Goldsboro, North Carolina, adjacent to the Lee plant. The facility includes five GE 7FA combustion turbines operating in simple cycle mode.

* * * * *

SECTION 3

DECOMMISSIONING COSTS

3.0 DECOMMISSIONING COSTS

BMcD has prepared decommissioning cost estimates for the Plants. When Progress determines that each site should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the site decommissioning costs. However, Progress will incur costs of decommissioning of the Plants and restoration of the site to the extent that those costs exceed the salvage value of equipment and bulk steel.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to dismantle all of the assets owned by Progress at the site, including power generating equipment and balance of plant facilities, as well as environmental site restoration activities.

For purposes of this study, BMcD and LVI have assumed that each site will be decommissioned as a single project, allowing the most cost effective demolition methods to be utilized. A summary of several of the means and methods that could be employed is summarized in the following paragraphs; however, means and methods will not be dictated to the contractor by BMcD. It will be the contractor's responsibility to determine means and methods that result in safely decommissioning the Plants at the lowest possible cost.

Asbestos remediation would take place prior to commencement of any other demolition activities. Abatement would need to be performed in compliance with all state and federal regulations, including, but not limited to requirements for sealing off work areas and maintaining negative pressure throughout the removal process. Final clearances and approvals would need to be achieved prior to performing further demolition activities.

High grade assets would then be removed from the site, to the extent possible. This would include items such as transformers, transformer coils, circuit breakers, electrical wire, condenser plates and tubes, and heater tubes. High grade assets include precious alloys such as copper, aluminum-brass tubes, stainless steel tubes, and other high value metals occurring in plant systems. High grade asset removal would occur up-front in the schedule, to reduce the potential for vandalism, to increase cash flow, and for separation of recyclable materials, in order to increase scrap recovery. Methods of removal vary with the location and nature of the asset. Small transformers, small equipment, and wire would likely be removed and shipped as-is for processing at a scrap yard. Large transformers, combustion turbines, steam turbines, and condensers would likely require some on-site disassembly prior to being shipped to a scrap yard.

Construction and Demolition (C&D) waste includes items such as non-asbestos insulation, roofing, wood, drywall, plastics, and other non-metallic materials. C&D waste would typically be segregated from scrap and concrete to avoid cross-contaminating of waste streams or recycle streams. C&D demolition crews could remove these materials with equipment such as excavators equipped with material handling attachments, skid steers, etc. This material would be consolidated and loaded into bulk containers for disposal.

In general, boilers and HRSGs could be felled and cut into manageable sized pieces on the ground. First the structures around the boilers would need to be removed using excavators equipped with shears and grapples. Stairs, grating, elevators, and other high structures would be removed using an "ultra high reach" excavator, equipped with shears. Following removal of these structures, the boilers or HRSGs would be felled, using explosive blasts. The boilers would then be dismantled using equipment such as excavators equipped with shears and grapples, and the scrap metal loaded onto trailers for recycling.

After the surrounding structures and ductwork have been removed, the stacks would be imploded, using controlled blasts. Following implosion the stack liners and concrete would be reduced in size to allow for handling and removal.

Balance of plant structures and foundations would likely be demolished using excavators equipped with hydraulic shears, hydraulic grapples, and impact breakers, along with workers utilizing open flame cutting torches. Steel components would be separated, reduced in size, and loaded onto trailers for recycling. Concrete would be broken into manageable sized pieces and stockpiled for crushing on-site. Concrete pieces would ultimately be loaded in a hopper and fed through a crusher to be sized for on-site disposal.

The Robinson Station would likely be demolished utilizing "ultra high reach" excavators equipped with shears and a concrete processor, excavators, and skid steers, since it cannot be felled, due to the proximity of the adjacent nuclear unit.

3.1 GENERAL DECOMMISSIONING ASSUMPTIONS FOR ALL SITES

The following assumptions were made as the basis of all of the cost estimates.

1. The estimates are inclusive of all cost necessary to properly dismantle and decommission all sites to a marketable or usable condition. For purposes of this study and the included cost estimates, the facilities will be restored to a condition suitable for industrial use.
2. All facilities will be decommissioned to zero generating output. Existing utilities will remain in place for use by the contractor for the duration of the demolition activities.
3. All work will take place in the most cost efficient method.
4. Labor costs are based on a regular 40 hour workweek without overtime.
5. It is assumed that all the power stations will be dismantled after all units at a single site are taken out of service, allowing dismantlement of entire sites at once.
6. Soil testing and any other on-site testing has not been conducted for this study.
7. Transmission switchyards and substations within the boundaries of the plant are not part of the demolition scope. Switchyards that are associated with the facilities only and are not part of the transmission system are included for demolition. For purposes of this study, the division between generation assets and transmission assets is at the high side of the generator step-up transformers.
8. The costs for relocation of transmission lines, or other transmission assets, are specifically excluded from the decommissioning cost estimates. Any costs necessary to support on-going operations of adjacent or newly proposed units will be allocated to the operating costs of the units not being decommissioned.
9. Step up transformers, auxiliary transformers, and spare transformers are included for demolition and scrap in all estimates.
10. Abatement of asbestos will precede any other work. After final air quality clearances have been reached, demolition can proceed.
11. All demolition and abatement activities, including removal of asbestos, will be done in accordance with any and all applicable Federal, State and Local laws, rules and regulations.
12. Progress Energy will remove or consume all burnable coal, fuel oil and chemicals prior to commencement of demolition activities.
13. If any PCB contaminated oil is encountered, it will be removed and disposed of properly. Estimated quantities of PCB contaminated oil were developed for each site based on data provided by Progress Energy.
14. Hazardous material abatement is included for all sites as necessary, including asbestos, mercury, and PCBs. Lead paint coated materials will be handled by certified personnel as necessary, but will not be removed prior to demolition.
15. No environmental costs have been included to address cleanup of contaminated soils, hazardous materials, or other conditions present on-site having a negative environmental impact, other than

those specifically listed in these assumptions. No allowances are included for unforeseen environmental remediation activities.

16. Handling and disposal of hazardous material will be performed in compliance with the approved methods of Progress Energy Environmental Services Department.
17. Refractory brick on the coal fired boilers is handled and disposed of as hazardous waste, due to the likelihood of the presence of arsenic contamination.
18. Existing ash ponds will be pumped dry, filled with inert debris, capped with 40 mil geo-membrane, geo-net drainage layer, 18 inches of soil, and vegetated cover.
19. Stormwater ponds will be pumped dry, filled with inert debris, capped with 40 mil geo-membrane, geo-net drainage layer, 18 inches of soil, and vegetated cover.
20. Cooling lakes will remain as-is.
21. Site areas will be graded to achieve suitable site drainage to natural drainage patterns, but grading will be minimized to the extent possible.
22. All above grade structures will be demolished. All below grade structures, including foundations, will be abandoned in-place unless deemed hazardous by Progress Energy or otherwise stated in the assumptions as being demolished.
23. All roads, paving, crushed rock surfacing, and rail lines will be abandoned in place, and be available for reuse.
24. Existing basements will be used to bury non-hazardous debris. Concrete in trenches and basements will be perforated to create drainage. Non-hazardous debris, such as concrete and brick, will be crushed and used as clean fill on-site once the capacity of all existing basements has been exceeded. All inert debris is disposed on-site, with the exception of the hydro-electric plants. Costs for offsite disposal are included for materials not classified as inert debris, and for all debris at the hydro-electric plants.
25. Major equipment, structural steel, combustion turbines, generators, inlet filters, exhaust stacks, transformers, electrical equipment, cabling, wiring, pump skids, above ground piping, and equipment enclosures for the above equipment are sold for scrap and removed from the Plant site by the demolition contractor. All other demolished materials are considered debris.
26. Except for the circulating water lines, underground piping will be abandoned in place. Circulating water system pipes will be capped, have the tops broken out, and backfilled with on-site soil.
27. Sewers, catch basins and ducts will be filled and sealed on the upstream side. Horizontal runs will be abandoned in place after being closed.

28. Costs are included to clean out the fuel oil tanks and lines. Costs have also been included to remove one foot of soil directly below each of the fuel oil tanks to account for the potential for this soil to be contaminated during normal operations.
29. Disturbed site areas will be seeded after they are graded to provide a suitable ground cover to prevent soil erosion.
30. Spare Parts inventories have been provided to BMcD by Progress Energy. It is assumed that spare parts having potential reuse will be transferred to other Progress Energy sites or sold on the secondary market prior to commencing dismantlement. For purposes of this study, BMcD has assumed that any spare parts, tools, inventory, or equipment in the buildings will be salvaged or sold for scrap, the value of which has been accounted for in the estimates.
31. Rolling stock, including rail cars, dozers, plant vehicles, etc. is assumed to be removed by Progress Energy prior to decommissioning.
32. Valuation and sale of land and all replacement generation costs are excluded from this scope.
33. For purposes of this study, it is assumed that none of the equipment will have a salvage value in excess of the scrap value of the materials in the equipment at the time of the decommissioning study. The decommissioning cost estimate is based on the end of useful life of each facility. All equipment, steel, copper, and other metals will be sold as scrap. Credits for salvage value are based on scrap value alone. Resale of equipment and materials is not included.
34. The scope of the costs included in this Study is limited to the decommissioning activities that will occur at the end of useful life of the facilities. Additional on-going costs may be required, including, but not limited to groundwater monitoring associated with ash pond closure and/or other environmental monitoring activities. These costs are excluded from the cost estimates provided in this Study.
35. Contingency is included in the cost estimate to cover expenses that are unknown at the time the estimate is prepared, but can reasonably be anticipated to be expended on the project. When preparing a cost estimate, there is always some uncertainty as to the precision of the quantities in the estimate, how work will be performed, and what work conditions will be like when the project is executed. Uncertainties are greater in a demolition project than in a construction project due to the nature of the drawings used for quantity takeoffs and the likelihood of encountering unknown conditions, such as hazardous materials, or environmental contamination. Other unknown conditions that could impact the costs include, but are not limited to, changing market conditions and weather delays. These uncertainties will impact the actual costs of the project relative to the estimated cost. The estimator is aware of these unknowns when preparing the cost estimate and

includes contingency to cover these costs. A 20% contingency was included on the direct costs in the estimates prepared as part of this study to cover unknowns.

36. Scrap value of steel is included at $320 per gross-ton.
37. Scrap value of copper is included at $2.89 per pound.
38. The current scrap metal values utilized in this study are on the higher end of the range relative to historical scrap metal pricing.
39. Pricing for all estimates is in 2011 dollars.
40. Market conditions may result in cost variations at the time of contract execution.

3.2 SITE SPECIFIC DECOMMISSIONING ASSUMPTIONS

3.2.1 Asheville

The following assumptions were made specific to the Asheville plant.

1. Unit 1 **-** has been assumed to have had approximately 50% of the asbestos removed from the boilers, 50% of asbestos removed from the steam turbines, and 20% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
2. Unit 2 **-** has been assumed to have had approximately 50% of the asbestos removed from the boilers, 50% of asbestos removed from the steam turbines, and 20% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
3. The old Unit 1 stack is assumed to contain asbestos. The old Unit 2 stack is asbestos free. The new combined wet stack is asbestos free.
4. The precipitators, SCRs, scrubbers, and steam turbines are all asbestos free.
5. The combustion turbines do not contain any asbestos.
6. The cooling lake will remain as-is.
7. Three transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. PCB testing results indicate that PCB levels are below 50 ppm. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 50 ppm and 500 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

8. The wastewater treatment facility is included for demolition.

3.2.2 Blewett

The following assumptions were made specific to the Blewett plant.

1. The dam associated with the power generation facility is not included for demolition. It is assumed that the dam will be required to remain in operation for flow control purposes. The powerhouse and penstocks will also remain in place to serve support flow control operations. The generators, transformers, and all other power generation equipment will be removed.
2. Although the powerhouse will remain, the cost of asbestos abatement in the powerhouse will be borne by Progress Energy and is included in the decommissioning cost estimates.
3. The CO2 shed associated with the engine plant includes panels that contain asbestos.
4. Ceiling tiles in the powerhouse and insulation around the small water tank on the island contain asbestos.
5. Additional areas around the powerhouse potentially contain asbestos, including, but not limited to, pipe insulation, sprayed decorative ceilings, plaster, gaskets, valve packing, floor tile and vinyl, specialty paint and coatings, roofing asphalt, joint compound, cord/rope, roofing felt, transite panels, ebony boards, mastics, electrical wire coating. An allowance for abatement of these potentially asbestos contaminated areas has been included in the cost estimates.
6. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. No PCB testing data has been provided to BMcD. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 50 ppm and 200 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.3 Darlington

The following assumptions were made specific to the Darlington plant.

1. Units 12 and 13 are asbestos free

2. Units 2, 4, 6, 7, 8, 10, 11 still have asbestos containing heat shields in place. Enpuricon, Inc. provided a cost estimate to remove these remaining heat shields for $18,480. This cost has been incorporated in the decommissioning estimates.
3. Units 1, 3, 5, 9 have had asbestos containing heat shields removed
4. The lube oil lines under the generators and water lines are assumed to contain asbestos. Costs for removal and disposal of this asbestos have been included in the cost estimates.
5. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. PCB testing results were provided to BMcD by Progress Energy. All recent tests indicate that PCB levels are below 50 ppm. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 5 ppm and 50 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.4 Marshall

The following assumptions were made specific to the Marshall plant.

1. The dam associated with the power generation facility is not included for demolition. It is assumed that the dam will be required to remain in operation for flow control purposes. The powerhouse and penstocks will also remain in place to serve support flow control operations. The generators, transformers, and all other power generation equipment will be removed.
2. Although the powerhouse will remain, the cost of asbestos abatement in the powerhouse will be borne by Progress Energy and is included in the decommissioning cost estimates.
3. Ceiling tiles in the powerhouse and flooring in the control room contain asbestos.
4. Additional areas around the powerhouse potentially contain asbestos, including, but not limited to, pipe insulation, sprayed decorative ceilings, plaster, gaskets, valve packing, floor tile and vinyl, specialty paint and coatings, roofing asphalt, joint compound, cord/rope, roofing felt, transite panels, ebony boards, mastics, electrical wire coating. An allowance for abatement of these potentially asbestos contaminated areas has been included in the cost estimates.
5. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. No PCB testing data has been provided to BMcD. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 50 ppm and 200 ppm. This

oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.5 Mayo

The following assumptions were made specific to the Mayo plant.

1. The boilers, steam turbines, critical piping, and other major equipment at the Mayo plant is assumed to be asbestos free, based on the age of the facility. Gaskets, packing, tiles, etc. are assumed to contain asbestos. The cost for handling and disposing of this asbestos containing material is included in the cost estimates.
2. The cooling lake will remain as-is.
3. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. PCB testing results were provided to BMcD by Progress Energy. All recent tests indicate that PCB levels are below 50 ppm. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 5 ppm and 50 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.
4. The bioreactor is included for demolition.

3.2.6 Morehead City

The following assumptions were made specific to the Morehead City plant.

1. The combustion turbine is assumed to contain asbestos insulation.
2. No PCB data is available for this facility. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 5 ppm and 50 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.7 Richmond

The following assumptions were made specific to the Richmond plant.

1. There is no asbestos at the Richmond site.
2. There are no PCBs at the Richmond site.

3.2.8 Robinson

The following assumptions were made specific to the Robinson plant.

1. Unit 1 - has been assumed to have had approximately 20% of the asbestos removed from the boiler, 20% of asbestos removed from the steam turbines, and 30% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
2. The stack is assumed to contain asbestos
3. The combustion turbine is assumed to contain asbestos insulation.
4. The on-site rail will remain to support the nuclear generating facility.
5. In areas where fuel oil tanks have leaked, the affected areas will be excavated down 5 feet below the existing ground surface level. This soil will be hauled off and disposed of in an appropriately licensed landfill. For purposes of this study, this depth of removal from the surface was selected as an assumed average depth of removal for the contaminated areas. The actual contamination depth may be shallower or deeper in some areas, but for purposes of this study, this average removal depth was assumed. During final decommissioning activities, soil sampling will be performed if needed, to verify removal of contaminated material.
6. In areas where fuel oil pipes have leaked, a trench will be excavated 5 feet wide by 10 feet below the existing ground surface level. This soil will be hauled off and disposed of in an appropriately licensed landfill. For purposes of this study, this depth and of removal from the surface and width of removal was selected as an assumed average area of contamination surrounding the fuel oil lines. The actual area of contamination may be smaller or larger in some areas, but for purposes of this study, this average removal area was assumed. During final decommissioning activities, soil sampling will be performed if needed, to verify removal of contaminated material
7. The cooling lake will remain as-is.
8. Areas of the ash pond are known to contain low levels of radiation. These areas will remain undisturbed in the ash pond.

9. No blasting will be allowed at this site. The Robinson coal fired unit will need to be dismantled in a controlled manner, since operation of the adjacent nuclear unit will continue. It is assumed that a high reach excavator will be utilized to remove light steel framing, decks, and support structures and also used with shears to cut into boiler skin and begin dismantling boiler tubes. Larger items, such as steam drums, columns, girders, and the economizer manifold will be torch cut and picked utilizing cranes and/or excavators. Once these items are on the ground, they will be dismantled and loaded onto trailers for recycling
10. Additional costs are included in the demolition cost estimates to cover gamma scanning for radiation contamination of all debris to be hauled off site.
11. Additional costs are included for decreased productivity and other costs related to security inspections and other security requirements of the nuclear facility.
12. Costs are included for replacing the guard towers related to the nuclear facility that are currently located on the coal fired boiler.
13. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. PCB testing results were provided to BMcD by Progress Energy. Most recent tests indicate PCB levels of approximately 110 ppm. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 50 ppm and 200 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.9 Roxboro

The following assumptions were made specific to the Roxboro plant.

1. Unit 1 has been assumed to have had approximately 90% of the asbestos removed from the boilers, 60% of asbestos removed from the steam turbines, and 60% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
2. Unit 2 has been assumed to have had approximately 60% of the asbestos removed from the boilers, 60% of asbestos removed from the steam turbines, and 60% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.

3. Unit 3 has been assumed to have had approximately 60% of the asbestos removed from the boilers, 60% of asbestos removed from the steam turbines, and 60% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
4. Unit 4 has been assumed to have had approximately 60% of the asbestos removed from the boilers, 60% of asbestos removed from the steam turbines, and 60% of asbestos removed from the critical piping. The cost of removal and disposal of the remaining asbestos is included in the cost estimates.
5. The old stacks are concrete stacks with a brick liner, with a layer of asbestos material in between the concrete and the brick. Unit 1 and Unit 2 stacks are approximately 400 feet tall. Unit 3 and Unit 4 stacks are approximately 800 feet tall. The cost of removal and disposal of this asbestos is included in the cost estimates.
6. In areas where fuel oil tanks have leaked, the affected areas will be excavated down 5 feet below the existing ground surface level. This soil will be hauled off and disposed of in an appropriately licensed landfill. For purposes of this study, this depth of removal from the surface was selected as an assumed average depth of removal for the contaminated areas. The actual contamination depth may be shallower or deeper in some areas, but for purposes of this study, this average removal depth was assumed. During final decommissioning activities, soil sampling will be performed if needed, to verify removal of contaminated material.
7. In areas where fuel oil pipes have leaked, a trench will be excavated 5 feet wide by 10 feet below the existing ground surface level. This soil will be hauled off and disposed of in an appropriately licensed landfill. For purposes of this study, this depth and of removal from the surface and width of removal was selected as an assumed average area of contamination surrounding the fuel oil lines. The actual area of contamination may be smaller or larger in some areas, but for purposes of this study, this average removal area was assumed. During final decommissioning activities, soil sampling will be performed if needed, to verify removal of contaminated material.
8. The cooling lake and intake canal will remain as-is.
9. Plant personnel indicated that 70% of the transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. No recent PCB testing has been performed. For purposes of this study, it will be assumed that PCB levels of the transformer oils are between 5 ppm and 50 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual

contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

10. The bioreactor is included for demolition.

3.2.10 Tillery

The following assumptions were made specific to the Tillery plant.

1. The dam associated with the power generation facility is not included for demolition. It is assumed that the dam will be required to remain in operation for flow control purposes. The powerhouse and penstocks will also remain in place to serve support flow control operations. The generators, transformers, and all other power generation equipment will be removed.
2. Although the powerhouse will remain, the cost of asbestos abatement in the powerhouse will be borne by Progress Energy and is included in the decommissioning cost estimates.
3. No known asbestos contamination has been identified; however, areas of potential asbestos contamination exist.
4. Additional areas around the powerhouse potentially contain asbestos, including, but not limited to, pipe insulation, sprayed decorative ceilings, plaster, gaskets, valve packing, floor tile and vinyl, specialty paint and coatings, roofing asphalt, joint compound, cord/rope, roofing felt, transite panels, ebony boards, mastics, electrical wire coating. An allowance for abatement of these potentially asbestos contaminated areas has been included in the cost estimates.
5. The recently installed oxygenation system will remain in place.
6. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. No PCB testing data has been provided to BMcD. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 50 ppm and 200 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.11 Walters

The following assumptions were made specific to the Walters plant.

1. The dam associated with the power generation facility is not included for demolition. It is assumed that the dam will be required to remain in operation for flow control purposes. The powerhouse and penstocks will also remain in place to serve support flow control operations. The generators, transformers, and all other power generation equipment will be removed.
2. Although the powerhouse will remain, the cost of asbestos abatement in the powerhouse will be borne by Progress Energy and is included in the decommissioning cost estimates.
3. The CO2 shed associated with the engine plant includes panels that contain asbestos.
4. A list of known asbestos contamination has been provided to BMcD by Progress Energy, and serves as the basis for the asbestos removal and disposal costs.
5. Additional areas around the powerhouse potentially contain asbestos, including, but not limited to, pipe insulation, sprayed decorative ceilings, plaster, gaskets, valve packing, floor tile and vinyl, specialty paint and coatings, roofing asphalt, joint compound, cord/rope, roofing felt, transite panels, ebony boards, mastics, electrical wire coating. An allowance for abatement of these potentially asbestos contaminated areas has been included in the cost estimates.
6. Transformers at the plant historically included PCB containing oil. These oils have all been removed, however, there is potential for PCB leach back from residual contamination in the transformer cores. No PCB testing data has been provided to BMcD. For purposes of this study, it will be assumed that PCB levels in all transformer oils are between 50 ppm and 200 ppm. This oil will be disposed of in accordance with applicable regulations. Foundations supporting equipment that contained PCBs will be assumed to contain residual contamination and will be removed and disposed of properly. The costs also include removal of one foot of soil beneath the pads for offsite disposal.

3.2.12 Wayne

The following assumptions were made specific to the Wayne plant.

1. There is no asbestos at the Wayne site.
2. The on-site diesel tanker trucks owned by Progress Energy are not included in the decommissioning cost estimates. These trucks will be sold or transferred prior to commencement of decommissioning activities.
3. There are no PCBs at the Wayne site.

3.3 RESULTS

BMcD has prepared estimates in current dollars (2011$) for the decommissioning of the Plants. These costs are summarized in Table 3-1. A breakdown of the decommissioning costs can be found in Appendix A.

Table 3-1: Decommissioning Cost Summary

Asset	Decommissioning Costs	Credits	Net Project Cost
Asheville	$33,757,000	($9,039,000)	$24,718,000
Blewett	$6,894,000	($1,090,000)	$5,804,000
Darlington	$6,348,000	($5,127,000)	$1,221,000
Marshall	$1,626,000	($179,000)	$1,447,000
Mayo	$54,296,000	($11,826,000)	$42,470,000
Morehead City	$186,000	($137,000)	$49,000
Richmond	$14,618,000	($11,138,000)	$3,480,000
Robinson	$23,938,000	($2,814,000)	$21,124,000
Roxboro	$154,870,000	($23,403,000)	$131,467,000
Tillery	$5,105,000	($1,444,000)	$3,661,000
Walters	$2,005,000	($1,391,000)	$614,000
Wayne	$2,654,000	($3,675,000)	($1,021,000)

* * * * *

SECTION 4
LIMITATIONS

4.0 LIMITATIONS

In preparation of this decommissioning study, BMcD has relied upon information provided by Progress Energy. BMcD acknowledges that it has requested the information from Progress Energy that it deemed necessary to complete this study. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of decommissioning costs are based on Engineer's experience, qualifications and judgment. Since Engineer has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Engineer does not guarantee the accuracy of its estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

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APPENDIX A

DECOMMISSOINING COST BREAKDOWNS

Table A-1
Asheville Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Asheville Plant						
Unit 1						
Asbestos Removal	$ -	$ -	$ -	$ 397,000	$ 397,000	$ -
Boiler	$ 756,000	$ 720,000	$ -	$ -	$ 1,476,000	$ -
Steam Turbine & Building	$ 538,000	$ 684,000	$ -	$ -	$ 1,222,000	$ -
Precipitator	$ 40,000	$ 27,000	$ -	$ -	$ 67,000	$ -
SCR/FGD	$ 18,000	$ 13,000	$ -	$ -	$ 31,000	$ -
Stack	$ 318,000	$ 194,000	$ -	$ -	$ 512,000	$ -
GSU & Foundation	$ 43,000	$ 54,000	$ -	$ -	$ 97,000	$ -
Hazardous Materials Disposal (Refractory, etc)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 2,611,000	$ -	$ 2,611,000	$ -
Debris	$ -	$ -	$ 975,000	$ -	$ 975,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,388,000)
Subtotal	**$ 1,713,000**	**$ 1,692,000**	**$ 3,586,000**	**$ 405,000**	**$ 7,396,000**	**$ (3,388,000)**
Unit 2						
Asbestos Removal	$ -	$ -	$ -	$ 406,000	$ 406,000	$ -
Boiler	$ 756,000	$ 720,000	$ -	$ -	$ 1,476,000	$ -
Steam Turbine & Building	$ 571,000	$ 695,000	$ -	$ -	$ 1,266,000	$ -
Precipitator	$ 41,000	$ 28,000	$ -	$ -	$ 69,000	$ -
SCR/FGD	$ 19,000	$ 13,000	$ -	$ -	$ 32,000	$ -
Stack	$ 93,000	$ 238,000	$ -	$ -	$ 331,000	$ -
GSU & Foundation	$ 93,000	$ 55,000	$ -	$ -	$ 148,000	$ -
Hazardous Materials Disposal (Refractory, etc)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 2,016,000	$ -	$ 2,016,000	$ -
Debris	$ -	$ -	$ 687,000	$ -	$ 687,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,448,000)
Subtotal	**$ 1,573,000**	**$ 1,749,000**	**$ 2,703,000**	**$ 414,000**	**$ 6,439,000**	**$ (3,448,000)**
Material Handling Facilities						
Demolition	$ 204,000	$ 109,000	$ -	$ -	$ 313,000	$ -
Gypsum & Coal Storage Area Restoration	$ -	$ -	$ -	$ 1,801,000	$ 1,801,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 209,000	$ -	$ 209,000	$ -
Debris	$ -	$ -	$ 52,000	$ -	$ 52,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (487,000)
Subtotal	**$ 204,000**	**$ 109,000**	**$ 261,000**	**$ 1,801,000**	**$ 2,375,000**	**$ (487,000)**
Combustion Turbine Unit 1						
Turbines & Foundations	$ 117,000	$ 88,000	$ -	$ -	$ 205,000	$ -
GSUs	$ 18,000	$ 13,000	$ -	$ -	$ 31,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Debris	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (548,000)
Subtotal	**$ 135,000**	**$ 101,000**	**$ 3,000**	**$ -**	**$ 239,000**	**$ (548,000)**
Combustion Turbine Unit 2						
Turbines & Foundations	$ 117,000	$ 88,000	$ -	$ -	$ 205,000	$ -
GSUs	$ 18,000	$ 13,000	$ -	$ -	$ 31,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Debris	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (604,000)
Subtotal	**$ 135,000**	**$ 101,000**	**$ 3,000**	**$ -**	**$ 239,000**	**$ (604,000)**
Common Facilities						
Cooling Water Intakes and Circulating Water Pumps	$ 82,000	$ 112,000	$ -	$ -	$ 194,000	$ -
Cooling Water Discharge Canal	$ 33,000	$ 185,000	$ -	$ -	$ 218,000	$ -
All BOP Buildings	$ 41,000	$ 15,000	$ -	$ -	$ 56,000	$ -
Closure of Ash Ponds	$ -	$ -	$ -	$ 9,000,000	$ 9,000,000	$ -
Fuel Oil Storage Tanks	$ 20,000	$ 64,000	$ -	$ -	$ 84,000	$ -
All Other Tanks	$ 16,000	$ 14,000	$ -	$ -	$ 30,000	$ -
PCB Oil Transportation and Disposal (>50 ppm to <500 ppm)	$ -	$ -	$ -	$ 109,000	$ 109,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ -	$ 242,000	$ 242,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 216,000	$ 216,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 40,000	$ 40,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Nuclear Device Removal and Disposal	$ -	$ -	$ -	$ 13,000	$ 13,000	$ -
Plant Washdown & Materials Disposal	$ -	$ -	$ -	$ 45,000	$ 45,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 36,000	$ -	$ 36,000	$ -
Debris	$ -	$ -	$ 13,000	$ -	$ 13,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (564,000)
Subtotal	**$ 192,000**	**$ 390,000**	**$ 49,000**	**$ 9,687,000**	**$ 10,318,000**	**$ (564,000)**
Asheville Plant Subtotal	**$ 3,952,000**	**$ 4,142,000**	**$ 6,605,000**	**$ 12,307,000**	**$ 27,006,000**	**$ (9,039,000)**
TOTAL COST (CREDIT)					**$ 27,006,000**	**$ (9,039,000)**
PROJECT INDIRECTS (5%)					**$ 1,350,000**	
CONTINGENGY (20%)					**$ 5,401,000**	
TOTAL PROJECT COST (CREDIT)					**$ 33,757,000**	**$ (9,039,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 24,718,000**	

Table A-2
Blewett Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Blewett Plant						
Combustion Turbine Unit 1						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ 7,000	$ 5,000	$ -	$ -	$ 12,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (168,000)
Subtotal	**$ 44,000**	**$ 33,000**	**$ -**	**$ -**	**$ 77,000**	**$ (168,000)**
Combustion Turbine Unit 2						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ -	$ 5,000	$ -	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (168,000)
Subtotal	**$ 37,000**	**$ 33,000**	**$ -**	**$ -**	**$ 70,000**	**$ (168,000)**
Combustion Turbine Unit 3						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ -	$ 5,000	$ -	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (168,000)
Subtotal	**$ 37,000**	**$ 33,000**	**$ -**	**$ -**	**$ 70,000**	**$ (168,000)**
Combustion Turbine Unit 4						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ -	$ 5,000	$ -	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (168,000)
Subtotal	**$ 37,000**	**$ 33,000**	**$ -**	**$ -**	**$ 70,000**	**$ (168,000)**
Combustion Turbine Common Facilities						
Asbestos Removal	$ -	$ -	$ -	$ 6,000	$ 6,000	$ -
PCB Oil Transportation and Disposal (>50 ppm to <500 ppm)	$ -	$ -	$ -	$ 37,000	$ 37,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ 44,000	$ 398,000	$ 442,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 67,000	$ 67,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 20,000	$ 20,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 9,000	$ 9,000	$ -
Subtotal	**$ -**	**$ -**	**$ 44,000**	**$ 537,000**	**$ 581,000**	**$ -**
Hydroelectric Units 1 - 6						
Demolition	$ 2,550,000	$ 1,104,000	$ -	$ -	$ 3,654,000	$ -
Debris	$ -	$ -	$ 11,000	$ -	$ 11,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (418,000)
Subtotal	**$ 2,550,000**	**$ 1,104,000**	**$ 11,000**	**$ -**	**$ 3,665,000**	**$ (418,000)**
Hydroelectric Common Facilities						
Asbestos Removal	$ -	$ -	$ -	$ 695,000	$ 695,000	$ -
PCB Oil Transportation and Disposal (>50 ppm to <200 ppm)	$ -	$ -	$ -	$ 37,000	$ 37,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ 66,000	$ 173,000	$ 239,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Subtotal	**$ -**	**$ -**	**$ 66,000**	**$ 916,000**	**$ 982,000**	**$ -**
Blewett Plant Subtotal	**$ 2,705,000**	**$ 1,236,000**	**$ 121,000**	**$ 1,453,000**	**$ 5,515,000**	**$ (1,090,000)**
TOTAL COST (CREDIT)					**$ 5,515,000**	**$ (1,090,000)**
PROJECT INDIRECTS (5%)					**$ 276,000**	
CONTINGENGY (20%)					**$ 1,103,000**	
TOTAL PROJECT COST (CREDIT)					**$ 6,894,000**	**$ (1,090,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 5,804,000**	

Table A-3
Darlington Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Darlington Plant						
Combustion Turbine Unit 1						
Asbestos Removal	$ -	$ -	$ -	$ 1,000	$ 1,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 7,000	$ 5,000	$ -	$ -	$ 12,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (316,000)
Subtotal	**$ 82,000**	**$ 59,000**	**$ -**	**$ 1,000**	**$ 142,000**	**$ (316,000)**
Combustion Turbine Unit 2						
Asbestos Removal	$ -	$ -	$ -	$ 4,000	$ 4,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 6,000	$ 5,000	$ -	$ -	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (333,000)
Subtotal	**$ 81,000**	**$ 59,000**	**$ -**	**$ 4,000**	**$ 144,000**	**$ (333,000)**
Combustion Turbine Unit 3						
Asbestos Removal	$ -	$ -	$ -	$ 1,000	$ 1,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 7,000	$ 5,000	$ -	$ -	$ 12,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (316,000)
Subtotal	**$ 82,000**	**$ 59,000**	**$ -**	**$ 1,000**	**$ 142,000**	**$ (316,000)**
Combustion Turbine Unit 4						
Asbestos Removal	$ -	$ -	$ -	$ 4,000	$ 4,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 6,000	$ 5,000	$ -	$ -	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (333,000)
Subtotal	**$ 81,000**	**$ 59,000**	**$ -**	**$ 4,000**	**$ 144,000**	**$ (333,000)**
Combustion Turbine Unit 5						
Asbestos Removal	$ -	$ -	$ -	$ 1,000	$ 1,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 6,000	$ 5,000	$ -	$ -	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (333,000)
Subtotal	**$ 81,000**	**$ 59,000**	**$ -**	**$ 1,000**	**$ 141,000**	**$ (333,000)**
Combustion Turbine Unit 6						
Asbestos Removal	$ -	$ -	$ -	$ 4,000	$ 4,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 6,000	$ 5,000	$ -	$ -	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (333,000)
Subtotal	**$ 81,000**	**$ 59,000**	**$ -**	**$ 4,000**	**$ 144,000**	**$ (333,000)**
Combustion Turbine Unit 7						
Asbestos Removal	$ -	$ -	$ -	$ 4,000	$ 4,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 6,000	$ 5,000	$ -	$ -	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (333,000)
Subtotal	**$ 81,000**	**$ 59,000**	**$ -**	**$ 4,000**	**$ 144,000**	**$ (333,000)**
Combustion Turbine Unit 8						
Asbestos Removal	$ -	$ -	$ -	$ 4,000	$ 4,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 6,000	$ 5,000	$ -	$ -	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (333,000)
Subtotal	**$ 81,000**	**$ 59,000**	**$ -**	**$ 4,000**	**$ 144,000**	**$ (333,000)**
Combustion Turbine Unit 9						
Asbestos Removal	$ -	$ -	$ -	$ 1,000	$ 1,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 6,000	$ 5,000	$ -	$ -	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (333,000)
Subtotal	**$ 81,000**	**$ 59,000**	**$ -**	**$ 1,000**	**$ 141,000**	**$ (333,000)**

Combustion Turbine Unit 10						
Asbestos Removal	$ -	$ -	$ -	$ 4,000	$ 4,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 9,000	$ 7,000	$ -	$ -	$ 16,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (328,000)
Subtotal	**$ 84,000**	**$ 61,000**	**$ -**	**$ 4,000**	**$ 149,000**	**$ (328,000)**
Combustion Turbine Unit 11						
Asbestos Removal	$ -	$ -	$ -	$ 4,000	$ 4,000	$ -
Turbines & Foundations	$ 73,000	$ 54,000	$ -	$ -	$ 127,000	$ -
GSUs	$ 6,000	$ 5,000	$ -	$ -	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 2,000	$ -	$ -	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (333,000)
Subtotal	**$ 81,000**	**$ 59,000**	**$ -**	**$ 4,000**	**$ 144,000**	**$ (333,000)**
Combustion Turbine Unit 12						
Turbines & Foundations	$ 93,000	$ 70,000	$ -	$ -	$ 163,000	$ -
GSUs	$ 12,000	$ 9,000	$ -	$ -	$ 21,000	$ -
On-site Concrete Crushing & Disposal	$ 5,000	$ -	$ 1,000	$ -	$ 6,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (474,000)
Subtotal	**$ 110,000**	**$ 79,000**	**$ 1,000**	**$ -**	**$ 190,000**	**$ (474,000)**
Combustion Turbine Unit 13						
Turbines & Foundations	$ 93,000	$ 70,000	$ -	$ -	$ 163,000	$ -
GSUs	$ 12,000	$ 9,000	$ -	$ -	$ 21,000	$ -
On-site Concrete Crushing & Disposal	$ 5,000	$ -	$ 1,000	$ -	$ 6,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (457,000)
Subtotal	**$ 110,000**	**$ 79,000**	**$ 1,000**	**$ -**	**$ 190,000**	**$ (457,000)**
Common Facilities						
BOP Buildings & Tanks	$ 130,000	$ 97,000	$ -	$ -	$ 227,000	$ -
Mechanical Pipings	$ 125,000	$ 94,000	$ -	$ -	$ 219,000	$ -
On-site Concrete Crushing & Disposal	$ 16,000	$ -	$ 3,000	$ -	$ 19,000	$ -
PCB Oil Transportation and Disposal (>5 ppm to <50 ppm)	$ -	$ -	$ 153,000	$ 153,000	$ 306,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ 441,000	$ 707,000	$ 1,148,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 971,000	$ 971,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 110,000	$ 110,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 22,000	$ 22,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Debris	$ -	$ -	$ 86,000	$ -	$ 86,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (572,000)
Subtotal	**$ 271,000**	**$ 191,000**	**$ 683,000**	**$ 1,974,000**	**$ 3,119,000**	**$ (572,000)**
Darlington Plant Subtotal	**$ 1,387,000**	**$ 1,000,000**	**$ 685,000**	**$ 2,006,000**	**$ 5,078,000**	**$ (5,127,000)**
TOTAL COST (CREDIT)					**$ 5,078,000**	**$ (5,127,000)**
PROJECT INDIRECTS (5%)					**$ 254,000**	
CONTINGENGY (20%)					**$ 1,016,000**	
TOTAL PROJECT COST (CREDIT)					**$ 6,348,000**	**$ (5,127,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 1,221,000**	

Table A-4
Marshall Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Marshall Plant						
Hydroelectric Units 1 & 2						
Demolition	$ 726,000	$ 354,000	$ -	$ -	$ 1,080,000	$ -
Debris	$ -	$ -	$ 20,000	$ -	$ 20,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (179,000)
Subtotal	**$ 726,000**	**$ 354,000**	**$ 20,000**	**$ -**	**$ 1,100,000**	**$ (179,000)**
Hydroelectric Common Facilities						
Asbestos Removal	$ -	$ -	$ -	$ 62,000	$ 62,000	$ -
PCB Oil Transportation and Disposal (>50 ppm to <200 ppm)	$ -	$ -	$ -	$ 10,000	$ 10,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ -	$ 118,000	$ 118,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Subtotal	**$ -**	**$ -**	**$ -**	**$ 201,000**	**$ 201,000**	**$ -**
Marshall Plant Subtotal	**$ 726,000**	**$ 354,000**	**$ 20,000**	**$ 201,000**	**$ 1,301,000**	**$ (179,000)**
TOTAL COST (CREDIT)					**$ 1,301,000**	**$ (179,000)**
PROJECT INDIRECTS (5%)					**$ 65,000**	
CONTINGENGY (20%)					**$ 260,000**	
TOTAL PROJECT COST (CREDIT)					**$ 1,626,000**	**$ (179,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 1,447,000**	

Table A-5
Mayo Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Mayo Plant						
Unit 1						
Asbestos Removal	$ -	$ -	$ -	$ 25,000	$ 25,000	$ -
Boiler	$ 2,526,000	$ 2,311,000	$ -	$ -	$ 4,837,000	$ -
Steam Turbine & Building	$ 1,700,000	$ 1,448,000	$ -	$ -	$ 3,148,000	$ -
Precipitator	$ 253,000	$ 231,000	$ -	$ -	$ 484,000	$ -
SCR/FGD	$ 402,000	$ 434,000	$ -	$ -	$ 836,000	$ -
Stack	$ 781,000	$ 1,946,000	$ -	$ -	$ 2,727,000	$ -
GSU & Foundation	$ 79,000	$ 117,000	$ -	$ -	$ 196,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 5,561,000	$ -	$ 5,561,000	$ -
Debris	$ -	$ -	$ 1,448,000	$ -	$ 1,448,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (8,766,000)
Subtotal	**$ 5,741,000**	**$ 6,487,000**	**$ 7,009,000**	**$ 33,000**	**$ 19,270,000**	**$ (8,766,000)**
Material Handling Facilities						
Demolition	$ 99,000	$ 212,000	$ -	$ -	$ 311,000	$ -
Coal Storage Area Restoration	$ -	$ -	$ -	$ 2,344,000	$ 2,344,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 238,000	$ -	$ 238,000	$ -
Debris	$ -	$ -	$ 125,000	$ -	$ 125,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,535,000)
Subtotal	**$ 99,000**	**$ 212,000**	**$ 363,000**	**$ 2,344,000**	**$ 3,018,000**	**$ (1,535,000)**
Common Facilities						
Cooling Water System and Circulating Water Pumps	$ 158,000	$ 349,000	$ -	$ -	$ 507,000	$ -
Cooling Tower & Basin	$ 47,000	$ 69,000	$ -	$ -	$ 116,000	$ -
Closure of Ash Ponds	$ -	$ -	$ -	$ 19,000,000	$ 19,000,000	$ -
Fuel Oil Storage Tanks	$ 59,000	$ 84,000	$ -	$ -	$ 143,000	$ -
All Other Tanks	$ 32,000	$ 27,000	$ -	$ -	$ 59,000	$ -
PCB Oil Transportation and Disposal (>5 ppm to <50 ppm)	$ -	$ -	$ -	$ 211,000	$ 211,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ -	$ 236,000	$ 236,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 59,000	$ 59,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 20,000	$ 20,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 4,000	$ 4,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Nuclear Device Removal and Disposal	$ 6,000	$ -	$ 8,000	$ 13,000	$ 27,000	$ -
Plant Washdown & Materials Disposal	$ 11,000	$ 8,000	$ 4,000	$ 23,000	$ 46,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 236,000	$ -	$ 236,000	$ -
Debris	$ -	$ -	$ 474,000	$ -	$ 474,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,525,000)
Subtotal	**$ 313,000**	**$ 537,000**	**$ 722,000**	**$ 19,577,000**	**$ 21,149,000**	**$ (1,525,000)**
Mayo Plant Subtotal	**$ 6,153,000**	**$ 7,236,000**	**$ 8,094,000**	**$ 21,954,000**	**$ 43,437,000**	**$ (11,826,000)**
TOTAL COST (CREDIT)					**$ 43,437,000**	**$ (11,826,000)**
PROJECT INDIRECTS (5%)					**$ 2,172,000**	
CONTINGENGY (20%)					**$ 8,687,000**	
TOTAL PROJECT COST (CREDIT)					**$ 54,296,000**	**$ (11,826,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 42,470,000**	

Table A-6
Morehead City Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Morehead City Plant						
Combustion Turbine Unit 1						
Asbestos Removal	$ -	$ -	$ -	$ 30,000	$ 30,000	$ -
Turbines & Foundations	$ 18,000	$ 13,000	$ -	$ -	$ 31,000	$ -
GSUs	$ 4,000	$ 3,000	$ -	$ -	$ 7,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (120,000)
Subtotal	**$ 22,000**	**$ 16,000**	**$ -**	**$ 30,000**	**$ 68,000**	**$ (120,000)**
Common Facilities						
Fuel Oil Tanks & Unloading Area	$ 8,000	$ 6,000	$ -	$ -	$ 14,000	$ -
PCB Oil Transportation and Disposal (>5 ppm to <50 ppm)	$ -	$ -	$ -	$ 10,000	$ 10,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ -	$ 29,000	$ 29,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 14,000	$ 14,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 1,000	$ 1,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 5,000	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (17,000)
Subtotal	**$ 8,000**	**$ 6,000**	**$ -**	**$ 67,000**	**$ 81,000**	**$ (17,000)**
Morehead City Plant Subtotal	**$ 30,000**	**$ 22,000**	**$ -**	**$ 97,000**	**$ 149,000**	**$ (137,000)**
TOTAL COST (CREDIT)					**$ 149,000**	**$ (137,000)**
PROJECT INDIRECTS (5%)					**$ 7,000**	
CONTINGENGY (20%)					**$ 30,000**	
TOTAL PROJECT COST (CREDIT)					**$ 186,000**	**$ (137,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 49,000**	

Table A-7
Richmond Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Richmond Plant						
Combustion Turbine Unit 1						
Turbines & Foundations	$ 254,000	$ 190,000	$ -	$ -	$ 444,000	$ -
GSUs	$ 34,000	$ 26,000	$ -	$ -	$ 60,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Debris	$ -	$ -	$ 5,000	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (679,000)
Subtotal	**$ 288,000**	**$ 216,000**	**$ 7,000**	**$ -**	**$ 511,000**	**$ (679,000)**
Combustion Turbine Unit 2						
Turbines & Foundations	$ 254,000	$ 190,000	$ -	$ -	$ 444,000	$ -
GSUs	$ 34,000	$ 26,000	$ -	$ -	$ 60,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Debris	$ -	$ -	$ 5,000	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (679,000)
Subtotal	**$ 288,000**	**$ 216,000**	**$ 7,000**	**$ -**	**$ 511,000**	**$ (679,000)**
Combustion Turbine Unit 3						
Turbines & Foundations	$ 254,000	$ 190,000	$ -	$ -	$ 444,000	$ -
GSUs	$ 34,000	$ 26,000	$ -	$ -	$ 60,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Debris	$ -	$ -	$ 5,000	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (593,000)
Subtotal	**$ 288,000**	**$ 216,000**	**$ 7,000**	**$ -**	**$ 511,000**	**$ (593,000)**
Combustion Turbine Unit 4						
Turbines & Foundations	$ 254,000	$ 190,000	$ -	$ -	$ 444,000	$ -
GSUs	$ 34,000	$ 26,000	$ -	$ -	$ 60,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Debris	$ -	$ -	$ 5,000	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (593,000)
Subtotal	**$ 288,000**	**$ 216,000**	**$ 7,000**	**$ -**	**$ 511,000**	**$ (593,000)**
Combustion Turbine Unit 5						
Turbines & Foundations	$ 254,000	$ 190,000	$ -	$ -	$ 444,000	$ -
GSUs	$ 34,000	$ 26,000	$ -	$ -	$ 60,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Debris	$ -	$ -	$ 5,000	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (588,000)
Subtotal	**$ 288,000**	**$ 216,000**	**$ 7,000**	**$ -**	**$ 511,000**	**$ (588,000)**
Combined Cycle - Powerblock 1 (480MW)						
2 GE 7FAs and HRSGs	$ 1,693,000	$ 1,270,000	$ -	$ -	$ 2,963,000	$ -
Steam Turbine & Pedestal	$ 264,000	$ 198,000	$ -	$ -	$ 462,000	$ -
3 GSUs & Electrical	$ 89,000	$ 67,000	$ -	$ -	$ 156,000	$ -
Cooling Tower and Basin, Cubic FT	$ 51,000	$ 60,000	$ -	$ -	$ 111,000	$ -
On-site Concrete Crushing & Disposal	$ 13,000	$ -	$ 51,000	$ -	$ 64,000	$ -
Debris	$ -	$ -	$ 71,000	$ -	$ 71,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,175,000)
Subtotal	**$ 2,110,000**	**$ 1,595,000**	**$ 122,000**	**$ -**	**$ 3,827,000**	**$ (3,175,000)**
Combined Cycle - Powerblock 2 (600MW)						
2 GE 7FAs and HRSGs	$ 1,958,000	$ 1,468,000	$ -	$ -	$ 3,426,000	$ -
Steam Turbine & Pedestal	$ 305,000	$ 229,000	$ -	$ -	$ 534,000	$ -
3 GSUs & Electrical	$ 103,000	$ 77,000	$ -	$ -	$ 180,000	$ -
Cooling Tower and Basin, Cubic FT	$ 63,000	$ 75,000	$ -	$ -	$ 138,000	$ -
On-site Concrete Crushing & Disposal	$ 14,000	$ -	$ 55,000	$ -	$ 69,000	$ -
Debris	$ -	$ -	$ 71,000	$ -	$ 71,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,536,000)
Subtotal	**$ 2,443,000**	**$ 1,849,000**	**$ 126,000**	**$ -**	**$ 4,418,000**	**$ (3,536,000)**
Common Facilities						
All BOP Buildings	$ 28,000	$ 21,000	$ -	$ -	$ 49,000	$ -
Fuel Oil Storage Tanks	$ 5,000	$ 4,000	$ -	$ -	$ 9,000	$ -
All Other Tanks	$ 7,000	$ 5,000	$ -	$ -	$ 12,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 657,000	$ 657,000	$ -
Miscellaneous Transformers	$ 7,000	$ 5,000	$ -	$ -	$ 12,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 105,000	$ 105,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 15,000	$ 15,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 1,000	$ -	$ 5,000	$ -	$ 6,000	$ -
Debris	$ -	$ -	$ 18,000	$ -	$ 18,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,295,000)
Subtotal	**$ 48,000**	**$ 35,000**	**$ 23,000**	**$ 788,000**	**$ 894,000**	**$ (1,295,000)**
Richmond Plant Subtotal	**$ 6,041,000**	**$ 4,559,000**	**$ 306,000**	**$ 788,000**	**$ 11,694,000**	**$ (11,138,000)**
TOTAL COST (CREDIT)					**$ 11,694,000**	**$ (11,138,000)**
PROJECT INDIRECTS (5%)					**$ 585,000**	
CONTINGENGY (20%)					**$ 2,339,000**	
TOTAL PROJECT COST (CREDIT)					**$ 14,618,000**	**$ (11,138,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 3,480,000**	

Table A-8
Robinson Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Robinson Plant						
Unit 1						
Asbestos Removal	$ -	$ -	$ -	$ 570,000	$ 570,000	$ -
Boiler	$ 869,000	$ 435,000	$ -	$ -	$ 1,304,000	$ -
Steam Turbine & Building	$ 313,000	$ 166,000	$ -	$ -	$ 479,000	$ -
Precipitator	$ 70,000	$ 31,000	$ -	$ -	$ 101,000	$ -
Stack	$ 626,000	$ 298,000	$ -	$ -	$ 924,000	$ -
GSU & Foundation	$ 69,000	$ 99,000	$ -	$ -	$ 168,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,066,000	$ -	$ 1,066,000	$ -
Debris	$ -	$ -	$ 726,000	$ -	$ 726,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,673,000)
Subtotal	**$ 1,947,000**	**$ 1,029,000**	**$ 1,792,000**	**$ 578,000**	**$ 5,346,000**	**$ (2,673,000)**
Material Handling Facilities						
Demolition	$ 116,000	$ 183,000	$ -	$ -	$ 299,000	$ -
Coal Storage Area Restoration	$ -	$ -	$ -	$ 1,631,000	$ 1,631,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Debris	$ -	$ -	$ 26,000	$ -	$ 26,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (48,000)
Subtotal	**$ 116,000**	**$ 183,000**	**$ 27,000**	**$ 1,631,000**	**$ 1,957,000**	**$ (48,000)**
Combustion Turbine Unit 1						
Turbines & Foundations	$ 37,000	$ 28,000	$ -	$ -	$ 65,000	$ -
GSUs	$ 7,000	$ 5,000	$ -	$ -	$ 12,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (93,000)
Subtotal	**$ 44,000**	**$ 33,000**	**$ -**	**$ -**	**$ 77,000**	**$ (93,000)**
Common Facilities						
Security Permitting Costs (i.e. Worker Background Checks, etc.)	$ 50,000	$ -	$ -	$ -	$ 50,000	$ -
Identification of any Radioactive Materials	$ -	$ -	$ -	$ 100,000	$ 100,000	$ -
Closure of Ash Ponds	$ -	$ -	$ -	$ 11,000,000	$ 11,000,000	$ -
Remediation of Soil Impacted by Fuel Oil Leak	$ -	$ -	$ -	$ 241,000	$ 241,000	$ -
PCB Oil Transportation and Disposal (>50 ppm to <200 ppm)	$ -	$ -	$ 26,000	$ 26,000	$ 52,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ 74,000	$ 118,000	$ 192,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 65,000	$ 65,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 3,000	$ 3,000	$ -
Mercury & Universal Waste Disposal	$ 6,000	$ 5,000	$ -	$ 11,000	$ 22,000	$ -
Nuclear Device Removal and Disposal	$ 6,000	$ -	$ 8,000	$ -	$ 14,000	$ -
Plant Washdown & Materials Disposal	$ 11,000	$ 8,000	$ 4,000	$ -	$ 23,000	$ -
Subtotal	**$ 73,000**	**$ 13,000**	**$ 112,000**	**$ 11,572,000**	**$ 11,770,000**	**$ -**
Robinson Plant Subtotal	**$ 2,180,000**	**$ 1,258,000**	**$ 1,931,000**	**$ 13,781,000**	**$ 19,150,000**	**$ (2,814,000)**
TOTAL COST (CREDIT)					**$ 19,150,000**	**$ (2,814,000)**
PROJECT INDIRECTS (5%)					**$ 958,000**	
CONTINGENGY (20%)					**$ 3,830,000**	
TOTAL PROJECT COST (CREDIT)					**$ 23,938,000**	**$ (2,814,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 21,124,000**	

Table A-9
Roxboro Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Roxboro Plant						
Unit 1						
Asbestos Removal	$ -	$ -	$ -	$ 700,000	$ 700,000	$ -
Boiler	$ 1,296,000	$ 1,184,000	$ -	$ -	$ 2,480,000	$ -
Steam Turbine & Building	$ 519,000	$ 510,000	$ -	$ -	$ 1,029,000	$ -
Precipitator	$ 123,000	$ 125,000	$ -	$ -	$ 248,000	$ -
SCR/FGD	$ 186,000	$ 200,000	$ -	$ -	$ 386,000	$ -
Stack	$ 302,000	$ 794,000	$ -	$ -	$ 1,096,000	$ -
GSU & Foundation	$ 34,000	$ 113,000	$ -	$ -	$ 147,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 3,415,000	$ -	$ 3,415,000	$ -
Debris	$ -	$ -	$ 1,993,000	$ -	$ 1,993,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,668,000)
Subtotal	**$ 2,460,000**	**$ 2,926,000**	**$ 5,408,000**	**$ 708,000**	**$ 11,502,000**	**$ (5,668,000)**
Unit 2						
Asbestos Removal	$ -	$ -	$ -	$ 1,177,000	$ 1,177,000	$ -
Boiler	$ 2,111,000	$ 1,906,000	$ -	$ -	$ 4,017,000	$ -
Steam Turbine & Building	$ 843,000	$ 828,000	$ -	$ -	$ 1,671,000	$ -
Precipitator	$ 141,000	$ 95,000	$ -	$ -	$ 236,000	$ -
SCR/FGD	$ 186,000	$ 200,000	$ -	$ -	$ 386,000	$ -
Stack	$ 302,000	$ 794,000	$ -	$ -	$ 1,096,000	$ -
GSU & Foundation	$ 55,000	$ 189,000	$ -	$ -	$ 244,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 3,080,000	$ -	$ 3,080,000	$ -
Debris	$ -	$ -	$ 3,389,000	$ -	$ 3,389,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (6,189,000)
Subtotal	**$ 3,638,000**	**$ 4,012,000**	**$ 6,469,000**	**$ 1,185,000**	**$ 15,304,000**	**$ (6,189,000)**
Unit 3						
Asbestos Removal	$ -	$ -	$ -	$ 1,391,000	$ 1,391,000	$ -
Boiler	$ 2,375,000	$ 2,232,000	$ -	$ -	$ 4,607,000	$ -
Steam Turbine & Building	$ 940,000	$ 924,000	$ -	$ -	$ 1,864,000	$ -
Precipitator	$ 231,000	$ 212,000	$ -	$ -	$ 443,000	$ -
SCR/FGD	$ 186,000	$ 200,000	$ -	$ -	$ 386,000	$ -
Stack	$ 781,000	$ 1,703,000	$ -	$ -	$ 2,484,000	$ -
GSU & Foundation	$ 61,000	$ 224,000	$ -	$ -	$ 285,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,749,000	$ -	$ 1,749,000	$ -
Debris	$ -	$ -	$ 3,949,000	$ -	$ 3,949,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,604,000)
Subtotal	**$ 4,574,000**	**$ 5,495,000**	**$ 5,698,000**	**$ 1,399,000**	**$ 17,166,000**	**$ (5,604,000)**
Unit 4						
Asbestos Removal	$ -	$ -	$ -	$ 1,391,000	$ 1,391,000	$ -
Boiler	$ 2,457,000	$ 2,302,000	$ -	$ -	$ 4,759,000	$ -
Steam Turbine & Building	$ 973,000	$ 956,000	$ -	$ -	$ 1,929,000	$ -
Precipitator	$ 235,000	$ 212,000	$ -	$ -	$ 447,000	$ -
SCR/FGD	$ 186,000	$ 200,000	$ -	$ -	$ 386,000	$ -
Stack	$ 195,000	$ 1,703,000	$ -	$ -	$ 1,898,000	$ -
GSU & Foundation	$ 63,000	$ 222,000	$ -	$ -	$ 285,000	$ -
Hazardous Materials Disposal (Refractory)	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,939,000	$ -	$ 1,939,000	$ -
Debris	$ -	$ -	$ 3,930,000	$ -	$ 3,930,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,605,000)
Subtotal	**$ 4,109,000**	**$ 5,595,000**	**$ 5,869,000**	**$ 1,399,000**	**$ 16,972,000**	**$ (3,605,000)**
Marterial Handling Facilities						
Demolition	$ 1,397,000	$ 749,000	$ -	$ -	$ 2,146,000	$ -
Gypsum & Coal Storage Area Restoration	$ -	$ -	$ -	$ 7,383,000	$ 7,383,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 280,000	$ -	$ 280,000	$ -
Debris	$ -	$ -	$ 288,000	$ -	$ 288,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (951,000)
Subtotal	**$ 1,397,000**	**$ 749,000**	**$ 568,000**	**$ 7,383,000**	**$ 10,097,000**	**$ (951,000)**
Common Facilities						
Cooling Water System and Circulating Water Pumps	$ 559,000	$ 112,000	$ -	$ -	$ 671,000	$ -
Cooling Towers & Basins	$ 47,000	$ 69,000	$ -	$ -	$ 116,000	$ -
Closure of Ash Ponds	$ -	$ -	$ -	$ 47,000,000	$ 47,000,000	$ -
Fuel Oil Storage Tanks	$ 70,000	$ 25,000	$ -	$ -	$ 95,000	$ -
All Other Tanks	$ 112,000	$ 95,000	$ -	$ -	$ 207,000	$ -
Remediation of Soil Impacted by Fuel Oil Leak	$ -	$ -	$ -	$ 711,000	$ 711,000	$ -
PCB Oil Transportation and Disposal (>5 ppm to <50 ppm)	$ -	$ -	$ 828,000	$ 828,000	$ 1,656,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ 478,000	$ 766,000	$ 1,244,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 179,000	$ 179,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 21,000	$ 21,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Nuclear Device Removal and Disposal	$ -	$ -	$ -	$ 13,000	$ 13,000	$ -
Plant Washdown & Materials Disposal	$ -	$ -	$ -	$ 91,000	$ 91,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 206,000	$ -	$ 206,000	$ -
Debris	$ -	$ -	$ 626,000	$ -	$ 626,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,386,000)
Subtotal	**$ 788,000**	**$ 301,000**	**$ 2,138,000**	**$ 49,628,000**	**$ 52,855,000**	**$ (1,386,000)**
Roxboro Plant Subtotal	**$ 16,966,000**	**$ 19,078,000**	**$ 26,150,000**	**$ 61,702,000**	**$ 123,896,000**	**$ (23,403,000)**
TOTAL COST (CREDIT)					**$ 123,896,000**	**$ (23,403,000)**
PROJECT INDIRECTS (5%)					**$ 6,195,000**	
CONTINGENGY (20%)					**$ 24,779,000**	
TOTAL PROJECT COST (CREDIT)					**$ 154,870,000**	**$ (23,403,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 131,467,000**	

Table A-10
Tillery Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Tillery Plant						
Hydroelectric Units 1 - 4						
Demolition	$ 2,016,000	$ 842,000	$ -	$ -	$ 2,858,000	$ -
Debris	$ -	$ -	$ 61,000	$ -	$ 61,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,444,000)
Subtotal	**$ 2,016,000**	**$ 842,000**	**$ 61,000**	**$ -**	**$ 2,919,000**	**$ (1,444,000)**
Hydroelectric Common Facilities						
Asbestos Removal	$ -	$ -	$ -	$ 610,000	$ 610,000	$ -
PCB Oil Transportation and Disposal (>50 ppm to <200 ppm)	$ -	$ -	$ -	$ 132,000	$ 132,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ -	$ 412,000	$ 412,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Subtotal	**$ -**	**$ -**	**$ -**	**$ 1,165,000**	**$ 1,165,000**	**$ -**
Tillery Plant Subtotal	**$ 2,016,000**	**$ 842,000**	**$ 61,000**	**$ 1,165,000**	**$ 4,084,000**	**$ (1,444,000)**
TOTAL COST (CREDIT)					**$ 4,084,000**	**$ (1,444,000)**
PROJECT INDIRECTS (5%)					**$ 204,000**	
CONTINGENGY (20%)					**$ 817,000**	
TOTAL PROJECT COST (CREDIT)					**$ 5,105,000**	**$ (1,444,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 3,661,000**	

Table A-11
Walters Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Walters Plant						
Hydroelectric Units 1 - 3						
Demolition	$ 696,000	$ 418,000	$ -	$ -	$ 1,114,000	$ -
Debris	$ -	$ -	$ 28,000	$ -	$ 28,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,391,000)
Subtotal	**$ 696,000**	**$ 418,000**	**$ 28,000**	**$ -**	**$ 1,142,000**	**$ (1,391,000)**
Hydroelectric Common Facilities						
Asbestos Removal	$ -	$ -	$ -	$ 172,000	$ 172,000	$ -
PCB Oil Transportation and Disposal (>50 ppm to <200 ppm)	$ -	$ -	$ -	$ 43,000	$ 43,000	$ -
Soil Removal Beneath PCB Equipment	$ -	$ -	$ -	$ 236,000	$ 236,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Subtotal	**$ -**	**$ -**	**$ -**	**$ 462,000**	**$ 462,000**	**$ -**
Walters Plant Subtotal	**$ 696,000**	**$ 418,000**	**$ 28,000**	**$ 462,000**	**$ 1,604,000**	**$ (1,391,000)**
TOTAL COST (CREDIT)					**$ 1,604,000**	**$ (1,391,000)**
PROJECT INDIRECTS (5%)					**$ 80,000**	
CONTINGENGY (20%)					**$ 321,000**	
TOTAL PROJECT COST (CREDIT)					**$ 2,005,000**	**$ (1,391,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 614,000**	

Table A-12
Wayne Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Wayne Plant						
Combustion Turbine Unit 10						
Turbines & Foundations	$ 117,000	$ 88,000	$ -	$ -	$ 205,000	$ -
GSUs	$ 17,000	$ 13,000	$ -	$ -	$ 30,000	$ -
On-site Concrete Crushing & Disposal	$ 1,000	$ -	$ 4,000	$ -	$ 5,000	$ -
Debris	$ -	$ -	$ 9,000	$ -	$ 9,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (570,000)
Subtotal	**$ 135,000**	**$ 101,000**	**$ 13,000**	**$ -**	**$ 249,000**	**$ (570,000)**
Combustion Turbine Unit 11						
Turbines & Foundations	$ 117,000	$ 88,000	$ -	$ -	$ 205,000	$ -
GSUs	$ 17,000	$ 13,000	$ -	$ -	$ 30,000	$ -
On-site Concrete Crushing & Disposal	$ 1,000	$ -	$ 4,000	$ -	$ 5,000	$ -
Debris	$ -	$ -	$ 9,000	$ -	$ 9,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (570,000)
Subtotal	**$ 135,000**	**$ 101,000**	**$ 13,000**	**$ -**	**$ 249,000**	**$ (570,000)**
Combustion Turbine Unit 12						
Turbines & Foundations	$ 117,000	$ 88,000	$ -	$ -	$ 205,000	$ -
GSUs	$ 17,000	$ 13,000	$ -	$ -	$ 30,000	$ -
On-site Concrete Crushing & Disposal	$ 1,000	$ -	$ 4,000	$ -	$ 5,000	$ -
Debris	$ -	$ -	$ 9,000	$ -	$ 9,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (570,000)
Subtotal	**$ 135,000**	**$ 101,000**	**$ 13,000**	**$ -**	**$ 249,000**	**$ (570,000)**
Combustion Turbine Unit 13						
Turbines & Foundations	$ 117,000	$ 88,000	$ -	$ -	$ 205,000	$ -
GSUs	$ 17,000	$ 13,000	$ -	$ -	$ 30,000	$ -
On-site Concrete Crushing & Disposal	$ 1,000	$ -	$ 4,000	$ -	$ 5,000	$ -
Debris	$ -	$ -	$ 9,000	$ -	$ 9,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (570,000)
Subtotal	**$ 135,000**	**$ 101,000**	**$ 13,000**	**$ -**	**$ 249,000**	**$ (570,000)**
Combustion Turbine Unit 14						
Turbines & Foundations	$ 117,000	$ 88,000	$ -	$ -	$ 205,000	$ -
GSUs	$ 15,000	$ 11,000	$ -	$ -	$ 26,000	$ -
On-site Concrete Crushing & Disposal	$ 1,000	$ -	$ 4,000	$ -	$ 5,000	$ -
Debris	$ -	$ -	$ 9,000	$ -	$ 9,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (613,000)
Subtotal	**$ 133,000**	**$ 99,000**	**$ 13,000**	**$ -**	**$ 245,000**	**$ (613,000)**
Common Facilities						
Admin and Other BOP Buildings	$ 10,000	$ 8,000	$ -	$ -	$ 18,000	$ -
Fuel Oil Tanks & Containment Wall	$ 139,000	$ 105,000	$ -	$ -	$ 244,000	$ -
Water Tanks	$ 50,000	$ 38,000	$ -	$ -	$ 88,000	$ -
Miscellaneous BOP Equipment	$ 70,000	$ 52,000	$ 1,000	$ -	$ 123,000	$ -
Soil Removal Beneath Fuel Oil Tank	$ -	$ -	$ -	$ 314,000	$ 314,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 60,000	$ 60,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
On-site Concrete Crushing & Disposal	$ 1,000	$ -	$ 4,000	$ -	$ 5,000	$ -
Debris	$ -	$ -	$ 11,000	$ -	$ 11,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (782,000)
Subtotal	**$ 270,000**	**$ 203,000**	**$ 16,000**	**$ 393,000**	**$ 882,000**	**$ (782,000)**
Wayne Plant Subtotal	**$ 943,000**	**$ 706,000**	**$ 81,000**	**$ 393,000**	**$ 2,123,000**	**$ (3,675,000)**
TOTAL COST (CREDIT)					**$ 2,123,000**	**$ (3,675,000)**
PROJECT INDIRECTS (5%)					**$ 106,000**	
CONTINGENGY (20%)					**$ 425,000**	
TOTAL PROJECT COST (CREDIT)					**$ 2,654,000**	**$ (3,675,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ (1,021,000)**	

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing *Late-Filed Exhibit No. 3* as filed in Docket No. E-2, Sub 1219, were served via electronic delivery or mailed, first-class, postage prepaid, upon all parties of record.

This, the 7th day of October, 2020.

/s/Mary Lynne Grigg

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