

**NORTH CAROLINA
DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES
DIVISION OF AIR QUALITY**

**PREVENTION OF SIGNIFICANT DETERIORATION
PRELIMINARY DETERMINATION**

AND

**NONATTAINMENT AREA
NEW SOURCE REVIEW DETERMINATION**

FOR

**TWO COMBINED CYCLE COMBUSTION TURBINES
AND
ASSOCIATED EQUIPMENT**

AT

**PLANT ROWAN COUNTY
SOUTHERN POWER COMPANY
SALISBURY, ROWAN COUNTY
NORTH CAROLINA**

October 16, 2008

Mailing List

NEWSPAPER	Mr. Len Clark Salisbury Post 131 W. Innes Street Salisbury, NC 28144 (704) 633-8950	Public Notice
OFFICIALS	Mr. William K. Cowan Manager, Rowan County 130 West Innes Street Salisbury, NC 28144 (704) 216-8180	Public Notice
LIBRARY	Ms. Rebecca Hyde Librarian, Rowan Public Library 201 W. Fisher Street Salisbury, NC 28144 (704) 216-8228	Preliminary Determination & Application
SOURCE	Mr. Scott Dial Plant Manager Plant Rowan County Southern Power Company 5755 North Carolina 801 Highway Salisbury, NC 28147 (704) 278-6601	Preliminary Determination & Public Notice
EPA	Ms. Heather Abrams Air Permits Section U.S. EPA Region 4 Sam Nunn Atlanta Federal Building 61 Forsyth Street, S.W. Atlanta, Georgia 30303-3104 (404) 562-9185	Preliminary Determination & Public Notice
	Preliminary Determination and Public Notice via electronic mail to: abrams.heather@epa.gov with cc to: forney.kathleen@epa.gov worley.gregg@epa.gov	
FLM	Mr. Bill Jackson National Forest Service 160A Zillicoa Street Asheville, NC 28801 (828) 257-4815	Preliminary Determination & Public Notice

MOORESVILLE
REGIONAL
OFFICE

Mr. Ron Slack
NC DAQ
Air Quality Regional Supervisor
610 East Center Ave.
Mooresville, NC 28115
(704) 663-1699

Preliminary Determination &
Public Notice

TABLE OF CONTENTS

SECTION	PAGE(s)
Fact Sheet	i
1.0 Introduction	1
1.1 Preliminary Determination and NAA NSR	4
2.0 General Description	
2.1 Process Description	7
2.2 Emissions	10
3.0 Regional Description	
3.1 Area Classification	11
4.0 Regulatory Analysis	
4.1 NSR Applicability and Required Analysis	12
4.2 NCDAQ Air Pollution Regulations	18
5.0 Best Available Control Technology Analysis	
5.1 BACT	35
5.2 LAER	36
5.3 Previous BACT/LAER Determinations.....	37
5.4 LAER Analysis for NO _x	38
5.5 BACT Analysis for NO _x as NO ₂	42
5.6 LAER Analysis for VOC	43
5.7 BACT Analysis for CO.....	46
5.8 BACT Analysis for PM/PM ₁₀	49
5.9 BACT Analysis for SO ₂ (State-only Requirement).....	51
5.10 BACT and LAER Summary.....	52

6.0	Air Quality Impact Analysis	
6.1	Project Description/Significant Emission Rate (SER) Analysis.....	55
6.2	Preliminary Impact Air Quality Modeling Analysis	56
6.3	Non Regulated Pollutant Impact Analysis	57
6.4	Additional Impact Analysis.....	58
6.5	Class I Area – Additional Requirements.....	59
6.6	NSR Air Quality Modeling Result Summary.....	60
7.0	Additional Requirements for NAA NSR	
7.1	Emission Offsets	62
7.2	Alternative Analysis.....	63
7.3	Compliance Demonstration.....	66

SAMPLE EMISSION CALCULATIONS.....	APPENDIX A
DRAFT PERMIT	APPENDIX B
PUBLIC NOTICE	APPENDIX C
RBLC NCDAQ SEARCH SUMMARY	APPENDIX D
APPLICATION	APPENDIX E

Fact Sheet

Applicant:

Plant Rowan County
Southern Power Company
5755 North Carolina 801 Highway
Salisbury, NC 28147
Contact: Brian Toth
(205) 257-7440

Consultant:

ENSR Consulting & Engineering (NC), Inc.
Raleigh, NC
Contact: Thomas Pritcher, P.E.
(919) 872-6600

- Plant Rowan County, Southern Power Company, Salisbury, NC, submitted a combined permit application under Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NAA NSR) programs to the North Carolina Division of Air Quality (NCDAQ), on February 14, 2008.
- The application was deemed complete by NCDAQ for review purposes pursuant to 40 CFR 51.166 (q)(1) and 15A NCAC 2D .0530(o) as of February 14, 2008.
- The facility is a PSD major stationary source, classified under the category of "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input". The facility emits or has the potential to emit 100 tons per year of particulate matter (PM), PM₁₀, PM_{2.5}, nitrogen oxides (as NO₂), sulfur dioxide (SO₂), and carbon monoxide (CO).
- The facility is also a major stationary source for NAA NSR. The facility emits or has the potential to emit 100 tons per year of nitrogen oxides (NO_x) and volatile organic compounds (VOC).
- The application includes a request to construct and operate two, natural gas-fired combined cycle combustion turbines and a cooling tower. This project will result in increases in emissions of PM/PM₁₀ (181.4 tons/yr), PM_{2.5} (99.7 tons/yr), NO_x (168.8 tons/yr), CO (519.5 tons/yr), VOC (45.0 tons/yr), SO₂ (10.5 tons/yr), and sulfuric acid mist [H₂SO₄ mist] (3.1 tons/yr). The emission rates of PM, PM₁₀, NO_x (as NO₂), and CO exceed their respective PSD significance thresholds of 25 tons/yr, 15 tons/yr, 40 tons/yr, and 100 tons/yr. Moreover, the emission rates of NO_x and VOC exceed the NAA NSR significance thresholds of 40 tons/yr each.
- NCDAQ proposes the following Lowest Achievable Emission Rate (LAER) and Best Available Control Technology (BACT) emission limits and control techniques for the proposed project equipment:

EMISSION SOURCE	POLLUTANT	EMISSION LIMITS		CONTROL TECHNOLOGY	CASE-BY-CASE BASIS
		Without Duct Burner	With Duct Burner		
Combustion Turbines (ID Nos. ES6A and ES6B)	NOx	2 ppmvd at 15% O ₂	2 ppmvd at 15% O ₂	DLN and SCR	LAER
	NOx (as NO ₂)	2 ppmvd at 15% O ₂ [First 500 hours of operation of SCR]	2 ppmvd at 15% O ₂ [First 500 hours of operation of SCR]	Same as Above	BACT
		2.5 ppmvd at 15% O ₂ [After 500 hours of operation of SCR]	2.5 ppmvd at 15% O ₂ [After 500 hours of operation of SCR]		
Combustion Turbines (ID Nos. ES6A and ES6B)	VOC (as CH ₄)	1.4 ppmvd at 15% O ₂	2 ppmvd at 15% O ₂	good combustion control and catalytic oxidation	LAER
Combustion Turbines (ID Nos. ES6A and ES6B)	CO	8 ppmvd at 15% O ₂	8 ppmvd at 15% O ₂	good combustion control	BACT
Combustion Turbines (ID Nos. ES6A and ES6B)	PM/PM10 (filterable and condensible)	0.0096 lb/million Btu	0.0099 lb/million Btu	use of low ash, low sulfur fuel and good combustion control	BACT
Cooling Tower (ID No. ES7)	PM/PM10 (filterable only)	0.0005% drift loss	0.0005% drift loss	drift eliminators	BACT
Combustion Turbines (ID Nos. ES6A and ES6B)	SO ₂	0.0006 lb/million Btu	0.0006 lb/million Btu	use of natural gas containing 0.2 grain/100 sft ³ sulfur content	BACT ["state-only" requirement]

- NCDAQ also proposes to require that the Permittee obtain DAQ-verified offsetting emission reductions for NOx and VOC in the amounts of 161 tons and 52 tons, respectively; by the time it commences operation of two, new combustion turbines.

SECTION 1.0
INTRODUCTION

Southern Power Company (“Southern Power”) has submitted to the North Carolina Division of Air Quality ("NCDAQ") a combined permit application (8000163.08A) under the Prevention of Significant Deterioration ("PSD") and Non-Attainment New Source Review ("NAA NSR") requirements of the Clean Air Act ("CAA") for the construction and operation of two, natural gas-fired combined cycle combustion turbines (ID Nos. ES-6A and ES-6B) and a cooling tower (ID No. ES-7) at Plant Rowan County, Salisbury, NC. This permit application will be processed as per the requirements in 15A NCAC 2D .0530 “Prevention of Significant Deterioration” and 15A NCAC 2Q .0531 “Sources in Non-attainment Area”.

This Southern Power facility operates under the current air permit 08758T10.

The permitted equipment at this facility are the following: three natural gas/No. 2 fuel oil-fired simple cycle combustion turbines, one natural gas/No. 2 fuel oil-fired combined cycle combustion turbine, one natural gas-fired combined cycle combustion turbine, two fuel oil storage tanks, one cooling tower, and several insignificant emission sources.

The facility is a PSD major stationary source, as defined in 40 CFR 51.166(b)(1)(i)(a), classified under the category of "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input". The facility emits or has the potential to emit 100 tons per year of particulate matter (PM), PM₁₀, PM_{2.5} (using PM₁₀ as a surrogate) nitrogen oxides (as NO₂), sulfur dioxide (SO₂), and carbon monoxide (CO).

In addition, the facility is a major stationary source, as defined in 40 CFR 51.165(a)(1)(iv)(A) for NAA NSR. The facility emits or has the potential to emit 100 tons per year of nitrogen oxides (NO_x) and volatile organic compounds (VOC).

This project will result in increases in emissions of PM/PM₁₀ (181.4 tons/yr), PM_{2.5} (99.7 tons/yr), NO_x (168.8 tons/yr), CO (519.5 tons/yr), VOC (45.0 tons/yr as CH₄), SO₂ (10.5 tons/yr), and sulfuric acid [H₂SO₄] mist (3.1 tons/yr).

The emission increases of PM, PM₁₀, NO_x (as NO₂), and CO exceed their respective PSD significance thresholds of 25 tons/yr, 15 tons/yr, 40 tons/yr, and 100 tons/yr, respectively. Thus, the project is subject to review and processing under the NCAC 2D .0530 "Prevention of Significant Deterioration" for emissions of PM, PM₁₀, NO_x (as NO₂) and CO.

Moreover, the emission increases of NO_x and VOC exceed the NAA NSR significance thresholds of 40 tons/yr each. Therefore, the project is also subject to review and processing under the NCAC 2D .0531 "Sources in Non-attainment Area" for emissions of NO_x and VOC.

The facility must also comply with other specific NC DAQ air pollution regulations where applicable.

Pursuant to the Federal Register notice on February 23, 1982, (47 FR 7836), North Carolina (NC) has full authority from the Environmental Protection Agency (EPA) to implement the PSD regulations in the State effective May 25, 1982. Accordingly, the NCDAQ will conduct a full PSD review for the proposed project. NC's State Implementation Plan (SIP) - approved PSD regulations have been codified in 15A NCAC 2D .0530, which implement the requirements of 40 CFR 51.166.

Also, pursuant to the Federal Register notice on July 26, 1982, (47 FR 32118), North Carolina (NC) has full authority from the Environmental Protection Agency (EPA) to implement the NAA NSR regulations in the State effective August 25, 1982. Accordingly, the NCDAQ will conduct a full NAA NSR for the proposed project. NC's SIP approved NAA NSR regulations have been codified in 15A NCAC 2D .0531, which implement the requirements of 40 CFR 51.165.

In accordance with PSD requirements, Southern Power has conducted a best available control technology (BACT) analysis, source impact analysis, additional impacts (soils, vegetation, visibility) analysis, and Class I area analysis.

In addition, Southern Power has performed analysis of lowest achievable emission rate (LAER), offsets and alternatives, in accordance with NAA NSR requirements.

The following emission limits and controls, as proposed by NCDAQ for approval, represent BACT or LAER, as applicable:

EMISSION SOURCE	POLLUTANT	EMISSION LIMITS		CONTROL TECHNOLOGY	CASE-BY-CASE BASIS
		Without Duct Burner	With Duct Burner		
Combustion Turbines (ID Nos. ES6A and ES6B)	NOx	2 ppmvd at 15% O ₂	2 ppmvd at 15% O ₂	DLN and SCR	LAER
	NOx (as NO ₂)	2 ppmvd at 15% O ₂ [First 500 hours of operation of SCR]	2 ppmvd at 15% O ₂ [First 500 hours of operation of SCR]	Same as Above	BACT
		2.5 ppmvd at 15% O ₂ [After 500 hours of operation of SCR]	2.5 ppmvd at 15% O ₂ [After 500 hours of operation of SCR]		
Combustion Turbines (ID Nos. ES6A and ES6B)	VOC (as CH ₄)	1.4 ppmvd at 15% O ₂	2 ppmvd at 15% O ₂	good combustion control and catalytic oxidation	LAER
Combustion Turbines (ID Nos. ES6A and ES6B)	CO	8 ppmvd at 15% O ₂	8 ppmvd at 15% O ₂	good combustion control	BACT
Combustion Turbines (ID Nos. ES6A and ES6B)	PM/PM10 (filterable and condensible)	0.0096 lb/million Btu	0.0099 lb/million Btu	use of low ash, low sulfur fuel and good combustion control	BACT
Cooling Tower (ID No. ES7)	PM/PM10 (filterable only)	0.0005% drift loss	0.0005% drift loss	drift eliminators	BACT
Combustion Turbines (ID Nos. ES6A and ES6B)	SO ₂	0.0006 lb/million Btu	0.0006 lb/million Btu	use of natural gas containing 0.2 grain/100 sft ³ sulfur content	BACT ["state-only" requirement]

The source impact and additional impact analyses, and Class I area evaluation concluded that the proposed project will not cause adverse air quality impacts in the surrounding community or the nearest Class I area; Linville Gorge National Wilderness Area.

In addition, for compliance with the NAA NSR requirements, the Permittee will be required to obtain NO_x and VOC offsets of approximately 161 tons and 52 tons, respectively, before the commencement of operation of the proposed equipment. Finally, the alternatives analysis demonstrates that the benefits of the proposed project significantly outweighs the environmental and social costs imposed as a result of its location, construction, or modification.

1.1 Preliminary Determination and NAA NSR

Southern Power's PSD/NAA NSR application has been reviewed by the NCDAQ, Permits Section staff, to determine compliance with the requirements of all NCDAQ air pollution regulations. The review was performed for the following:

- PSD including determination of BACT with consideration of non-PSD regulated toxic pollutants, source impact analysis, additional impact analysis on soils, vegetation and visibility, and Class I analysis;
- NAA NSR including determination of offsetting emissions reductions, LAER, compliance with all applicable requirements under the Clean Air Act, and alternative analysis.
- Compliance with the North Carolina Air Quality Rules at 15A NCAC 2D and 2Q.

The NCDAQ, Permits Section staff has conducted a preconstruction review of the application and made a preliminary determination that the proposed project will comply with all applicable North Carolina air quality regulations including the PSD and NAA NSR requirements. Therefore, the NCDAQ proposes to issue an air permit for the modification described in Section

1 above, with specific permit conditions and emission limits. This approval for both the PSD and NAA NSR is contingent upon the following findings:

- A demonstration that BACT is applied to each emission unit that will contribute to increase in emissions of any pollutant above the significance threshold.
- A demonstration that National Ambient Air Quality Standards (NAAQS) and PSD Class II increments will not be violated as a result of emissions from the proposed project.
- A demonstration that emissions from the proposed project will neither cause adverse impacts to soils and vegetation nor cause degradation of visibility, and that economic growth associated with the project will not cause a significant increase in regional air pollutant levels.
- A demonstration that air emissions resulting from the proposed project will not adversely impact any PSD Class I area.
- A demonstration that the LAER is applied to each emission unit that will contribute to increase in emissions of any non-attainment pollutant above the significance threshold.
- The Permittee is required to obtain offsets in the same non-attainment area for emission increases in any non-attainment pollutant above significance threshold prior to commencement of operation.
- A demonstration that all major sources owned or operated by the Permittee are in compliance or on a schedule for compliance, with all applicable limitations and standards under the CAA.
- A demonstration that analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed project significantly outweigh the

environmental and social costs imposed as a result of its location, construction or modification.

- A determination that the NC SIP is being adequately implemented for the non-attainment area in which the proposed source is constructed or modified.

The remainder of this report contains a review by NCDAQ of the demonstration and analyses presented by Southern Power. Sections 2 and 3 of this report present a general description of the proposed project and a description of the site location. Section 4 presents a regulatory analysis of the North Carolina and Federal air quality regulations that apply to the project construction and operation. Section 5 contains the BACT and LAER analyses. Section 6 presents the results of the air quality analyses. Section 7 includes discussion on compliance with all remaining requirements under NAA NSR. Sample emission calculations have been included in Appendix A while the NCDAQ draft air permit is contained in Appendix B.

In addition, the application must undergo adequate public participation. The NCDAQ solicits and encourages participation by the general public, industry, and other affected persons impacted by the proposed project. Specific public notice requirements and a 30-day public comment period are required before the NCDAQ can take final action on this application. Appendix C contains a copy of the public notice.

SECTION 2.0

GENERAL DESCRIPTION

2.1 Process Description

2.1.1 Existing Operations

Southern Power operates an electric power production facility at Plant Rowan County. The facility has been classified under the Standard Industrial Classification (SIC) code 4911 "Electric Services". Southern Power is the Southern Company subsidiary that owns and operates power generation assets that have been constructed for the wholesale market. As indicated in Section 1 above, the existing operations at the facility comprise three natural gas/No. 2 fuel oil-fired simple cycle combustion turbines, one natural gas/No. 2 fuel oil-fired combined cycle combustion turbine, one natural gas-fired combined cycle combustion turbine, two fuel oil storage tanks, one cooling tower, and several insignificant emission sources.

2.1.2 Proposed Modifications

Southern Power is proposing to construct and operate two, natural gas-fired combined cycle combustion turbines (ID Nos. ES-6A and ES-6B) and a cooling tower (ID No. ES-7) at Plant Rowan County.

The key elements of the proposed project are described as follows:

Gas Turbines

The proposed project includes the installation of two, GE MS7001FA (7FA) natural gas-fired combined-cycle combustion turbines, each equipped with its own duct-fired heat recovery steam generator (HRSG) and a common steam turbine generator, producing a total of 630 MW of electricity. This arrangement (2 combined cycle turbines and 1 steam turbine) is typically called

“2-on-1 block”. The total nominal generating capacity for the entire facility (all permitted and proposed turbines) after the modification will be 1,700 MW.

The proposed combined cycle turbines will be fired with pipeline quality gas only for all 8,760 hours of operation. Each gas turbine power block will include an advanced firing temperature combustion turbine air compressor section, gas combustion system (utilizing lean premix dry low NOx combustors), power turbine, and a generator.

The gas turbine is the main component of a combined-cycle power system. First, the intake air is filtered, then, cooled using evaporative cooling techniques, and finally, compressed in a multiple-stage axial flow compressor. Then, the compressed air and fuel are mixed and burned in the turbine combustion chamber. Lean pre-mix dry low NOx combustors minimize the emissions of NOx while combusting natural gas. Hot exhaust gases from the combustion chamber are expanded through a multi-stage power turbine that results in energy to drive both the air compressor and power generator. The gas turbine will produce nominally 170 MW each. Exhaust gases exit the power turbine at approximately 1100 °F.

The exhaust gases exiting the power turbine are ducted to a boiler commonly known as a HRSG where steam is produced and routed to a steam turbine generator to generate additional electricity. Natural gas-fired duct burners located within the HRSGs are used for supplementary firing to increase steam output when necessary.

The combustion turbines are designed to operate in the dry low-NOx mode at loads from about 50 percent to up to base load rating.

Heat Recovery Steam Generator

A horizontal, natural circulation, three-pressure level HRSG system will extract heat from the exhaust of the proposed combined cycle gas turbines. Exhaust gas entering the HRSG at approximately 1100°F will be cooled to 200°F as a result of the heat exchange across HRSG heat

exchangers. Steam production in the HRSG will be augmented at times using duct burners fired by natural gas. The heat from the turbines and duct burners will be used for additional steam generation and natural gas/feed water heating. The HRSG will include a high-pressure superheater, high-pressure evaporator, high-pressure economizer, reheat section (to reheat partially expanded steam), intermediate-pressure superheater, intermediate-pressure evaporator, intermediate-pressure economizer, low-pressure superheater, low-pressure evaporator, and surface condensate/feed water preheater. The evaporators in the HRSG convert saturated liquid into a superheated steam and thus produce steam for additional power generation. The surface condenser uses cooling tower water to condense the steam exiting the steam turbine. As the steam is condensed, the condensate flows to the surface condenser hotwell.

Steam Turbine

The proposed project includes one reheat, condensing steam turbine with variable pressure operation. The high-pressure portion of the steam turbine receives high-pressure super-heated steam from the HRSG that exhausts to the reheat section for the HRSG. The steam from the reheat section of the HRSG is supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure turbine also receives excess low-pressure superheated steam from the HRSG that exhausts to the surface condenser. The steam turbine set is designed to produce approximately 340 MW of electrical output without additional fuel consumption and approximately 290 MW with the addition of duct firing.

Process Cooling

One twelve-cell cooling tower, with drift eliminators for particulate control, will be integral to operation of the proposed combined cycle combustion turbine electrical generation system. The majority of cooling water will be used in the surface condenser to absorb the heat rejected from the combined cycle process and input to the inlet air chiller. Water from the cooling tower is commonly referred to as "main" cooling water. A dedicated set of cooling water pumps is provided for this service. Additional cooling water will be required for auxiliary plant cooling.

Cooling tower water is not used for direct cooling of plant auxiliaries. A closed loop auxiliary cooling system consisting of pumps, expansion tank, and heat exchanges is provided for auxiliary plant cooling. Cooling tower water is circulated through a set of plate and frame heat exchangers to cool the closed loop coolant, usually a glycol/water mixture. This is commonly referred to as "auxiliary" cooling water. A set of auxiliary cooling water pumps (separate from main cooling water pumps) is provided for this duty.

2.2 Emissions

Emissions from Southern Power facility include PM, PM₁₀, PM_{2.5}, SO₂, NO_x, CO, and VOC. A detailed emission summary for actual emissions and emissions increases due to proposed project are included in Section 4.

SECTION 3.0
REGIONAL DESCRIPTION

3.1 Area Classification

The facility is located in Rowan County. The facility coordinates are 35° 43' 50" (latitude) and 80° 36' 04" (longitude). The surrounding site (3-km region) is characterized as primarily rural. Within this predominantly rural area are agricultural and forest/undeveloped land, and widely scattered businesses and/or residences.

Air Quality in Rowan County is classified with respect to the NAAQS as listed below:

Pollutant	Attainment Status
PM ₁₀	Attainment
PM _{2.5}	Attainment
Sulfur Dioxide	Attainment
Nitrogen Dioxide	Attainment
Carbon Monoxide	Attainment
Ozone	Non-attainment
Lead	Attainment

Rowan County is considered a Class II Area with ambient air increments for PM₁₀, SO₂, and NO_x.

The closest Class I Area from this facility is the Linville Gorge National Wilderness Area, which is located approximately 125 kilometers west-northwest of the facility.

SECTION 4.0

REGULATORY ANALYSIS

The following discussion pertains to the regulatory requirements that must be met for the proposed modification of the Southern Power facility. These requirements include NSR regulations and other State and federally enforceable air quality regulations.

4.1 NSR Applicability and Required Analysis

The basic goal of the PSD regulations is to ensure that the air quality in attainment areas (e.g., Rowan County, NC, for PM₁₀, PM_{2.5}, NO_x (as NO₂), SO₂, CO, and lead) does not significantly deteriorate while maintaining a margin for future industrial growth. The PSD regulations focus on industrial facilities, both new and modified major sources.

In areas not meeting the NAAQS (e.g., Rowan County, NC, for ozone) and in ozone transport regions, the NSR program is implemented through NAA NSR. A major new source or major modification that would be located in a nonattainment area must meet the more stringent requirements that ensure that the new source's emissions will be controlled to the level of lowest achievable emission rate; that more than equivalent offsetting emission reductions ("emissions offsets") will be obtained from existing sources; and that there will be progress toward achievement of the NAAQS.

The US Environmental Protection Agency (EPA)'s latest revisions governing the NSR regulations are included in the Federal Register (67 FR 80186, December 31, 2002; 68 FR 63021, November 7, 2003; 70 FR 71612, November 29, 2005; 72 FR 32526, June 13, 2007, 72 FR 72607, December 21, 2007, and 73 FR 28321, May 16, 2008). As indicated in Section 1, effective May 25, 1982 and August 25, 1982, the NCDAQ received full authority from the EPA to implement PSD and NAA NSR regulations, respectively, in the State.

Under PSD requirements, all major new or modified stationary sources of air pollutants as defined in §169 of the Federal Clean Air Act (CAA) must be reviewed and permitted prior to construction by EPA or the appropriate permitting authority, as applicable, in accordance with §165 of CAA. A "major stationary source" is defined as any one of 28 named source categories (such as "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input"), which emits or has a potential to emit (PTE) 100 tons per year of any regulated NSR pollutant, or any other stationary source, which emits or has the potential to emit 250 tons per year of any regulated NSR pollutant.

All major new and modified stationary sources of air pollutants in NAA must be reviewed and permitted prior to construction by EPA or the appropriate permitting authority, as applicable, as per the requirements in §173 of CAA. A "major stationary source" under NAA NSR is defined as any source, which emits or has a potential to emit (PTE) 100 tons per year of any regulated NSR pollutant. There are lower thresholds applicable to "major stationary source" under NAA NSR, based upon the severity of nonattainment for a particular pollutant (e.g., 50 tons per year threshold for VOC in "serious" ozone nonattainment area, 25 tons per year threshold for VOC in "severe" ozone nonattainment area, etc.).

The Southern Power facility is an existing PSD major stationary source, classified under the category of "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input". It emits or has a potential to emit 100 tons per year of PM, PM₁₀, PM_{2.5}, SO₂, NO_x (as NO₂), and CO.

Moreover, the facility is an existing major stationary source under NAA NSR, as it emits or has a potential to emit 100 tons per year of NO_x, and VOCs.

Because the existing facility is considered a major stationary source, any modification to an existing major source resulting in significant emission increases for any regulated NSR pollutants, is subject to NSR review and must meet appropriate review requirements. Thus, the emission increases as a result of this modification must be compared to the "significance levels"

as listed in 40 CFR 51.166(b)(23)(i) and 51.165(a)(x)(A) to determine which pollutants must undergo PSD and NAA NSR review.

The company has performed the PSD and NAA NSR applicability analysis as follows by determining if the project results in emission increase of any regulated NSR pollutant above the respective significance thresholds.

Using the "actual-to-potential test", the Permittee has performed emission calculations for actual (pre change) and potential (after change) emissions for all regulated NSR pollutants. The actual emissions for a new emissions unit (such as two, combined cycle combustion turbine and a cooling tower) have been assumed to be zero because it has not yet been constructed nor it has begun "normal source operation". The potential emissions for these emissions units have been estimated using the "potential to emit" concept.

In brief, the potential emissions for the combustion turbines have been based on the worst-case hourly heat input rates from five operating loads (power augmentation, 100% duct burner, 100% w/o duct burner, 75%, and 50%) and three ambient temperatures (95°F, 65°F, and 0°F), and 8,760 hours of operation per year for each turbine (4,000 hours with duct firing and 4,760 hours without duct firing) and emission limits proposed by the Permittee for various pollutants. For the cooling tower, the potential emissions have been based on 8,760 hours of operation.

Table 4-1 Emission Increases for the Proposed Project

Compounds	PSD or NAA NSR Significant Emission Rates Tons Per Year	Net Emissions Increase/Decrease Tons Per Year	PSD Major Modification Review Required?	NAA NSR Major Modification Review Required?
PM	25	181.41	Yes	-
PM ₁₀	15	181.41	Yes	-

Compounds	PSD or NAA NSR Significant Emission Rates Tons Per Year	Net Emissions Increase/Decrease Tons Per Year	PSD Major Modification Review Required?	NAA NSR Major Modification Review Required?
PM _{2.5} ¹	-	99.74	-	-
SO ₂	40	10.47	No	-
NO _x (as NO ₂)	40	139.75	Yes	-
NO _x (ozone precursor)	40	139.75	-	Yes
CO	100	519.47	Yes	-
VOC (ozone precursor)	40	45.03	-	Yes
Lead	0.6	Negligible	No	-
Sulfuric Acid Mist	7	3.05	No	-

Using this procedure and as shown in Table 4-1 above, the following can be concluded:

- The change in emissions due to the project for PM, PM₁₀, NO_x (as NO₂), and CO, will exceed their respective PSD significance thresholds, and hence, PSD major modification review is required for these pollutants.
- The change in emissions due to the project for NO_x and VOCs, will exceed their respective NAA NSR significance thresholds, and hence, NAA NSR major modification review is required for these pollutants.

¹ For PM_{2.5}, NC DAQ will use PM₁₀ as a surrogate to satisfy all applicable PSD requirements.

EPA has issued a final rule on "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM_{2.5})" at 73 FR 28321, May 16, 2008 with an effective date of July 15, 2008. For SIP-Approved PSD programs such as North Carolina's PSD program in 15A NCAC 2D .0530, the State (NC) can continue implementing PM₁₀ program as a surrogate to meet the PSD program requirements for PM_{2.5} pursuant to the 1997 guidance entitled "Interim Implementation for the New Source Review Requirements for PM_{2.5}", John Seitz, EPA. See Page 28341 of this rulemaking.

- For all other remaining pollutants – SO₂², lead, and sulfuric acid mist, the change in emissions due to the project will be less than their respective PSD significance thresholds, and thus PSD major modification review is not required for these pollutants.

Thus, Southern Power performed the following reviews and analyses related to PSD and NAA NSR for emissions of PM, PM₁₀, NO_x (as NO₂), CO, NO_x, and VOCs, from the combined cycle combustion turbines and cooling tower. These reviews and analyses are required to be performed for each affected new or modified emission unit at which emission increase of any regulated air pollutant equal or exceed its significance threshold, as per 15A NCAC 2D .0530 and 15A NCAC 2D .0531.

- BACT determination
- source impact analysis
- air quality analysis
- additional impacts analysis including effects on soils, vegetation, and visibility
- Class I analysis
- LAER determination
- emissions offsets certification
- compliance demonstration for all applicable limitations or standards under the CAA
- alternatives analysis

Under PSD regulations, the determination of the necessary emission control equipment is developed through a BACT review. BACT is defined, in pertinent part, at 40 CFR 51.166 (b)(12) as:

An emissions limitation... based on the maximum degree of reduction for each pollutant... which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account

² As per 15A NCAC 2D .0530(h), this "minor modification" for SO₂ is required to comply with the "state-only" BACT requirements.

energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.

The BACT requirements are intended to ensure that the control systems incorporated in the design of the proposed facility reflect the latest control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the facility. Additionally, the BACT analysis must consider the impacts of noncriteria pollutants and unregulated toxic air pollutants, if any are emitted, when making the BACT decision for regulated pollutants. Under the BACT requirements of the PSD regulations, all BACT emission limits must, at a minimum, comply with any applicable standard of performance under 40 CFR Part 60 (New Source Performance Standards) and Part 61 (National Emission Standards for Hazardous Air Pollutants), and the North Carolina State Implementation Plan (SIP). A discussion of the BACT determination for the proposed project can be found in Section 5 of this document.

Under NAA NSR regulations, the determination of the necessary emission control equipment is developed through a LAER review. LAER is defined, in pertinent part, at Section II.A.18 of Appendix S to 40 CFR 51 as:

The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of source...or the most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source..."

The most stringent emissions limitation contained in a SIP for a class or category of source must be considered LAER, unless a more stringent emissions limitation has been achieved in practice or the SIP limitation is demonstrated by the applicant to be unachievable. By definition, LAER cannot be less stringent than any applicable New Source Performance Standard (Part 60). Unlike BACT, the LAER requirement places less emphasis on economic, energy, or environmental

factors. A discussion of the LAER determination for the proposed project can be found in Section 5 of this document.

4.2 NCDAQ Air Pollution Regulations

In addition to the NSR requirements, the NCDAQ has promulgated air quality rules under Title 15A NCAC Subchapter 2D and 2Q.

The NCDAQ emission control regulations that affect the proposed modification are summarized below:

Regulation	Affected Sources	Comment
2Q .0101	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B) and a Cooling Tower (ID No. ES-7)	A permit is required for all sources of air emissions not specifically exempted. These sources are processed under the 2Q .0300 program. They are required to be permitted with specific conditions and cannot be categorized as insignificant emission sources under 2Q .0503(7) or (8).
2D .0503	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B)	Allowable emissions of PM from burning of natural gas in the duct burners of combustion turbines shall not exceed the emission limit, established in 2D .0503(c).
2D .0515	Cooling Tower (ID No. ES-7)	Allowable PM emission rate depends upon the process rate.
2D .0521	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B)	Visible emissions cannot exceed 20 percent opacity.
2D .0524	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B)	The turbines are subject to New Source Performance Standards (NSPS) Subpart KKKK in 40 CFR 60.4305. Hence, it must comply with all applicable provisions of this NSPS.
2D .0530	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B) and a Cooling Tower (ID No. ES-7)	PSD review is required for a major modification.
2D .0531	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B)	NAA NSR is required for a major modification for non-attainment pollutants (such as VOCs and NOx) in Rowan County.

2D .0532	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B) and a Cooling Tower (ID No. ES-7)	The Permittee must evaluate how new emissions of PM2.5 from the proposed equipment impact the nearby non-attainment area of Davidson County for PM2.5. The proposed sources are NOT subject to this requirement.
2D .0535	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B) and a Cooling Tower (ID No. ES-7)	Emissions in excess of established permit limits that last for more than 4 hours require notification to the Director within 24 hours.
2D .0902(f)	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B)	The Permittee shall install and operate reasonably available control technology upon start-up for VOC.
2D .1111	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B)	New lean pre-mix gas fired turbines are subject to only initial notification requirements under Maximum Achievable Control Technology (MACT) Subpart YYYY as per 40 CFR 63.6095.
2D .1402(d)	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B)	The Permittee shall install and operate reasonably available control technology upon start-up for NOx.
2D .1418	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B)	NOx emissions from the new combustion turbine cannot exceed 0.15 lb/million Btu for gaseous fuel and 0.18 lb/million Btu for liquid fuels, or the NOx emissions from this turbine cannot exceed BACT and LAER limits established under 2D .0530 and .0531, respectively, whichever requires the greater degree of reduction.
2Q .0402	Two, Combined Cycle Combustion Turbines (ID Nos. ES-6A and ES-6B)	Permittee is required to submit Acid Rain application by the deadline in future, as per the applicable requirement.

4.2.1 15A NCAC 2Q .0101 - Required Air Quality Permits

This regulation requires the owner or operator of all sources for which there is an ambient air quality or emission control standard, that is not exempted from permit requirements, to apply for an air quality permit. The owner or operator of a source required to have a permit shall not begin construction or operation of the source without first obtaining a permit. The proposed combined cycle combustion turbines and a cooling tower are not exempt from permitting. Thus, Southern

Power is required to file an air permit application and obtain a revised permit prior to any construction or change in method of operation of these sources. Southern Power has submitted the required application and information sufficient to obtain an air quality permit, including all information required pursuant to 15A NCAC 2D .0530 "Prevention of Significant Deterioration" and .0531 "Sources in Nonattainment Area".

4.2.2 15A NCAC 2D .0503 - Particulates from Fuel Burning Indirect Heat Exchangers

This regulation establishes PM emission standard for all indirect heat exchangers except for electric utility boilers. PM emissions from the duct burners of each combustion turbine are subject to this applicable requirement.

Maximum heat input rates of all existing (permitted) indirect heat exchangers and the new combustion turbines (ID Nos. ES6A and ES6B) [duct burners of each turbine only] have been considered for establishing the PM emission rate for combustion turbines (ID Nos. ES6A and ES6B), as per 2D .0503(e).

$$\text{ES6} = 16.74 \text{ million Btu/hr (operation date 2003)}$$

$$\text{ES6A} = 542 \text{ million Btu/hr (operation 2011)}$$

$$\text{ES6B} = 542 \text{ million Btu/hr (operation 2011)}$$

$$\text{Total} = 1100.74 \text{ million Btu/hr}$$

$$\begin{aligned} E &= 1.090 \times (1100.74)^{-0.2594} \\ &= 0.18 \text{ lb PM/million Btu heat input} \end{aligned}$$

Each of these turbines are subject to the PM emission limit of 0.0099 lb/million Btu as established in Section 5 below (i.e., PM/PM10 BACT). Compliance with the PM emission standard of 2D .0503 is expected, as the potential emission rate (0.0099 lb/million Btu) is less than the allowable emission rate (0.18 lb/million Btu).

4.2.3 15A NCAC 2D .0515 - Particulates From Miscellaneous Industrial Processes

Allowable emissions of particulate matter from any industrial process for which no other emission control standards are applicable shall not exceed the amounts calculated by the following equation:

$$E = 4.10 \times P^{0.67} \text{ for } P \leq 30 \text{ tons per hour}$$

or

$$E = 55.0 \times P^{0.11} - 40 \text{ for } P > 30 \text{ tons per hour}$$

where: E = allowable emission rate in pounds per hour

P = process weight in tons per hour

Liquid and gaseous fuels and combustion air are not considered as part of the process weight.

Based on the recirculation water rate of 8.7 million gallons per hour and a density of 8.34 pounds per gallon at 59 °F, the process rate can be estimated as 36,279 tons/hr. Therefore, allowable PM emission rate is 134.55 lbs/hr.

The Permittee has calculated a maximum PM emission rate of 0.82 lb/hr, based upon an assumed TDS concentration of 2,250 ppm and a total drift rate of 0.0005%.

Therefore, compliance with this requirement is expected.

4.2.4 15A NCAC 2D .0521 - Control of Visible Emissions

The intent of this Rule is to prevent, abate and control emissions generated from fuel burning operations and industrial processes where visible emissions can be reasonably expected to occur, except during startup, shutdowns, and malfunctions approved as such according to procedures approved under 15A NCAC 2D .0535.

For sources manufactured after July 1, 1971, visible emissions shall not be more than 20 percent opacity when averaged over a six-minute period. However, except for sources required to install, operate, and maintain continuous opacity monitoring systems (COMS), compliance with the 20 percent opacity limit shall be determined as follows:

- i. No six-minute period exceeds 87 percent opacity;
- ii. No more than one six-minute period exceeds 20 percent opacity in any hour; and
- iii. No more than four six-minute periods exceed 20 percent opacity in any 24-hour period.

Excess emissions during startup and shutdown shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(g). Excess emissions during malfunctions shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(c).

All periods of excess emissions shall be included in the determinations in paragraphs i. and ii. above, until such time that the excess emissions are exempted according to the procedures in 2D .0535.

The new, combustion turbines will be subject to this standard. Visible emissions due to burning of natural gas are expected to be negligible due to inherently clean fuel. Compliance is expected.

Visible emissions from the cooling tower will be primarily in the form of water vapor. Hence, the cooling tower is NOT subject to this requirement.

4.2.5 15A NCAC 2D .0524 - New Source Performance Standards

EPA Administrator has promulgated a final rule under 40 CFR 60 Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines".

Applicability

The regulation applies to each stationary combustion turbine with a peak load equal to or greater than 10 million Btu per hour based on higher heating value, which commenced construction, modification, or reconstruction after February 18, 2005.

Only heat input rate to the combustion turbine should be included when determining whether or not this NSPS is applicable to the proposed turbines. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, the NSPS does apply to emissions from any associated HRSG and duct burners.

The construction of each of the new combustion turbines at the Southern Power facility will commence in 2009. The peak load heat input rate of each of the turbines (without the heat input of duct burners) is 1,914.4 million Btu/hr. Hence, the proposed combustion turbines are subject to this regulation.

Emission Limits for NO_x

The proposed turbines are subject to an emission standard of 15 ppm at 15 percent O₂ or 0.43 lb/MWh, when fired with natural gas. The HRSGs, if operating independently of the combustion turbines, then, they will be subject to an emission standard of 54 ppm at 15 percent O₂ or 0.86 lb/MWh, when fired with natural gas or other fuels.

The proposed turbines are designed to reduce NO_x emissions to 2 ppm at 15 percent O₂, using low-NO_x combustors and selective catalytic reduction while burning natural gas. Hence, compliance with the above NO_x emission limits is expected. The actual compliance with these emission standards will be verified during the initial performance test.

The Permittee had stated that the HRSGs would not be operating independently of the combustion turbines and thus, it had concluded that the 54 ppm emission limit for NOx emissions would not be applicable to the proposed turbines.

DAQ agrees with the Permittee that the 54 ppm NOx emission standard is not applicable for these turbines and thus will not include it in the air permit.

Emission Limits for SO₂

These turbines will be subject to an emission limit of 0.9 lb/MWh gross output or the turbines must not burn any fuel, which contains the total potential sulfur emissions in excess of 0.06 lb SO₂/million Btu heat input.

The proposed turbines will burn pipeline quality natural gas. Using 0.2 grains sulfur/100 ft³ sulfur content and 1,020 Btu/sft³ heat content for natural gas, the SO₂ emission rate for the turbine can be estimated as 0.00056 lb/million Btu. Hence, compliance is expected while firing natural gas.

General Compliance Requirements

The Permittee must operate and maintain the proposed combustion turbines, dry low NOx burners, SCRs, and any monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times during start-up, shutdown, and malfunction.

When an affected combustion turbine with heat recovery utilizes a common steam header with one or more combustion turbines, the Permittee shall either:

Determine compliance with the applicable NO_x emissions limits by measuring the emissions combined with the emissions from the other combustion turbine(s) utilizing the common heat recovery unit; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

If the Permittee is not using water injection to control NO_x emissions, the Permittee must perform annual performance tests (subsequent to initial performance test) to demonstrate continuous compliance. If the NO_x emission result from the performance test is less than or equal to 75 percent of the NO_x emission limit for the turbine, the frequency of testing can be reduced to once every two years for subsequent performance tests. If the results of any subsequent performance test exceed 75 percent of the NO_x emission limit, the Permittee must resume the annual performance tests.

As an alternate to the performance tests, the Permittee can

- install, calibrate, maintain, and operate NO_x CEM or
- applicable continuous parameter monitoring systems for dry low-NO_x combustors and SCR or
- with the DAQ approval for the affected units which are also subject to Part 75, monitor the NO_x emission rate using the Part 75 Appendix E methodology or the low mass emissions methodology in §75.19.

The Permittee must monitor the total sulfur content of the fuel being fired in the turbine, except that the Permittee can elect not to monitor the total sulfur content of the fuel combusted in the turbine provided that the fuel is demonstrated not to exceed potential sulfur emissions of 0.06 lb SO₂/million Btu heat input.

To make a demonstration that the potential sulfur emissions of 0.06 lb SO₂/million Btu heat input are not exceeded, the Permittee can elect to use valid purchase contract, tariff sheets or transportation contract for the total sulfur content for natural gas is less than 20 grains of sulfur or less per 100 sft³ for the continental US. Alternatively, the Permittee can use representative fuel sampling data to show that the sulfur content of the natural gas does not exceed 0.06 lb SO₂/million Btu heat input.

If the Permittee chooses not to demonstrate compliance with the sulfur content of the fuel as above and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day. The Permittee can also develop custom fuel schedules to determine total sulfur content of gaseous fuels. The regulation includes two, custom sulfur monitoring schedules, which are available without prior EPA approval.

Reporting

For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this Subpart, the Permittee must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. For each affected unit that performs annual performance tests in accordance with §60.4340(a), the Permittee must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

Performance Tests

The Permittee is required to conduct initial and subsequent performance tests as per §60.4400 and §60.4415 for NO_x and sulfur dioxide, respectively, with such exemptions as may be allowed.

NO_x

The Permittee is required to conduct initial performance test within 60 days after achieving the maximum production rate but not later than 180 days of initial start-up for NO_x for each combustion turbine.

It should be noted here that under 40 CFR 60 Subpart GG (Standards of Performance for Stationary Gas Turbines) EPA has waived the initial performance test requirements for the other identical turbines (with no manufacturer deviation) located at the same location and burning the same fuel, contingent upon the stack test results of the identical combustion turbine showing the high compliance margin with the NO_x emission standard. Refer to EPA ADI Control Numbers 0300035, 0100007, and 0300053.

Thus, DAQ will require initial performance testing for only one of two combustion turbines (ID Nos. ES6A and ES6B).

The Permittee is required to perform annual testing (no more than 14 calendar months following the previous performance test) for NO_x, if the Permittee is not using water injection to comply.

Each performance test for NO_x must be conducted at ± 25 percent of 100 percent peak load or at the highest achievable load point if at least 75 percent peak load cannot be achieved in practice. Three runs are required for each performance test and each run must last for a minimum 20 minutes. The ambient temperature for each test run must be above 0 °F.

If the NO_x emission result from any annual performance test is less than or equal to 75 percent of the NO_x emission limit for the proposed combustion turbine, the frequency of testing can be reduced to once every two years for subsequent performance tests. If the results of any subsequent performance test exceed 75 percent of the NO_x emission limit, the Permittee must resume the annual performance tests.

SO₂

The Permittee is required to conduct initial performance test within 60 days after achieving the maximum production rate but not later than 180 days of initial start-up for sulfur dioxide on each turbine. Similar to rationale given above for NO_x initial performance testing, DAQ will require stack testing for SO₂ on only one combustion turbine instead of both.

Each subsequent test for sulfur dioxide shall be conducted once every year (no more than 14 calendar months following the previous performance test). The Permittee can opt not to demonstrate compliance with SO₂ stack limit and can instead opt for fuel sulfur limit to comply with the sulfur stack-testing requirement.

If the Permittee opts to determine fuel sulfur to comply with the stack-testing requirement, then the Permittee must **monitor** total sulfur content of the fuel being fired in the turbine. The sulfur content of the fuel must be determined using total sulfur methods in §60.4415. The Permittee must monitor natural gas once per unit operating day if the fuel is supplied without intermediate bulk storage.

Alternatively, the Permittee can choose **not to monitor** the total potential sulfur emissions of the fuel combusted in the turbine, if it can be demonstrated that the fuel does not exceed 0.06 lb SO₂/million Btu in continental areas. This demonstration can be performed by using the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the maximum sulfur for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet. The other option for demonstration is through

representative fuel sampling data showing that the potential sulfur emissions of the fuel does not exceed 0.06 lb SO₂/million Btu in continental areas. In this case, the Permittee must provide at a minimum the amount of data in Section 2.3.1.4 or 2.3.2.4. of Appendix D of Part 75.

4.2.6 15A NCAC 2D .0530 - Prevention of Significant Deterioration

Facilities classified as major for PSD and applying for a significant modification are subject to all the requirements as defined in 15A NCAC 2D .0530. These requirements include:

- A demonstration that BACT is applied to each emission unit that will emit any PSD regulated pollutant that is emitted above the significant threshold.
- A demonstration that neither allowable PSD ambient air increments nor NAAQS will be violated as a result of the emissions from the proposed project.
- A demonstration that emissions from the proposed project will neither cause adverse impacts to soils and vegetation nor cause degradation of visibility, and that economic growth associated with the project will not cause a significant increase in regional air pollutant levels.
- A demonstration that air emissions resulting from the proposed facility will not adversely impact any PSD Class I area.

For additional details on the PSD regulatory analysis, please refer to Section 4.1 above.

4.2.7 15A NCAC 2D .0531 - Sources in Nonattainment Areas

Facilities classified as major for NAA NSR and applying for a significant modification are subject to the requirements in 15A NCAC 2D .0531. These requirements include:

- A demonstration that the LAER is applied to each emission unit that will contribute to an increase in emissions of any non-attainment pollutant above the significance threshold.

- A certification from the Permittee that it will obtain offsets for emission increases in any non-attainment pollutant above significance threshold.
- A demonstration that all major sources owned or operated by the Permittee are in compliance or on a schedule for compliance, with all applicable limitations and standards under the CAA.
- A demonstration that an analysis of alternative sites, sizes, production processes, and environmental control techniques has been performed.
- A determination that NC SIP is being adequately implemented for the non-attainment area in which the proposed source is constructed or modified.

For additional details on NAA NSR regulatory analysis, please refer to Section 4.1 above.

4.2.8 15A NCAC 2D .0532 - Sources Contributing to an Ambient Violation

This rule applies to new major stationary sources and major modifications to which 15A NCAC 2D .0531 does not apply and which would contribute to a violation of a national ambient air quality standard but which would not cause a new violation. To issue a permit to a new or modified source to which this Rule applies, the Director shall determine that the source will meet the following conditions:

- A demonstration that the LAER is applied to each emission unit that will contribute to increase in emissions of any non-attainment pollutant above the significance threshold.
- A certification from the Permittee that it will obtain offsets for emission increases showing the improvements in air quality for the locality in which it has contributed to a NAAQS violation, if the increases exceed its significance threshold.

- A demonstration that all major sources owned or operated by the Permittee are in compliance or on a schedule for compliance, with all applicable limitations and standards under the CAA.

The Permittee needs to demonstrate that its PM10 emissions do not contribute to a violation of PM2.5 NAAQS in adjoining Davidson County.

The Permittee has shown that the maximum impacts of PM10 emissions from the proposed modifications will be 4.38 ug/m³ and 0.64 ug/m³, for 24-hr and annual averaging periods, respectively. These impacts are less than their respective Significant Impact Levels (SILs) of 5 ug/m³ and 1 ug/m³, respectively. Hence, the proposed modifications are not subject to the requirements of 15A NCAC 2D .0532. Refer to Section (c)(5)(I) and (J) under this rule.

4.2.9 15A NCAC 2D .0535 - Excess Emissions Reporting and Malfunctions

This regulation applies to all permitted facilities and outlines the procedures of reporting excess emissions as a result of malfunctions or operational upsets. The facility owner/operator must notify the appropriate regional office of any excess emissions that last for greater than four hours. This report must be made within 24 hours of becoming aware of the occurrence.

4.2.10 15A NCAC 2D .0902(f) - Reasonably Available Control Technology for VOC

Southern Power facility, located in Rowan County, is subject to RACT for VOC because the facility wide VOC potential to emit exceeds the 100 tons per year threshold. All new sources (such as combustion turbines) not constructed before March 1, 2007 must be in compliance with RACT for VOC upon start-up. Refer to 2D .0902(f) and .0909(g)(2).

DAQ believes that the LAER requirements for VOC for combustion turbines in Section 5.5 below would assure at least RACT level control, and hence, it will not require any additional demonstration for VOC RACT.

4.2.11 NCAC 2D .1111 - Maximum Achievable Control Technology

Applicability

EPA has promulgated MACT Subpart YYYY for emissions of hazardous air pollutants (HAP) from stationary combustion turbines. The MACT applies to stationary combustion turbines located at major sources. Stationary combustion turbine, which commenced construction after January 14, 2003, have been defined as "new stationary combustion turbine".

In addition, EPA has stayed the effectiveness of the emissions and operating limitations for the new sources in the lean premix gas-fired turbines and diffusion flame gas-fired turbines subcategories on August 18, 2004. The owner or operator of a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine must comply with only the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this Subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

The proposed combustion turbine is a "new stationary combustion turbine" as its commencement of construction will be in 2008 or after, and it will be located at a major source. Also, it is of "lean premix gas-fired turbine" type. Hence, the Permittee will be required to comply with only Initial Notification requirement until EPA takes final action on this stay.

4.2.12 15A NCAC 2D .1402(d) - Reasonably Available Control Technology for NOx

Southern Power facility, located in Rowan County, is subject to RACT for NOx because the facility wide NOx potential to emit exceed 100 tons per year threshold. All new sources (such as combustion turbines) not constructed before March 1, 2007 must be in compliance with RACT for NOx upon start-up. Refer to 2D .1402(d) and .1403(e)(2).

DAQ believes that the LAER requirements for NO_x for combustion turbines in Section 5.4 below would assure at least RACT level control, and hence, it will not require any additional demonstration for NO_x RACT.

4.2.13 15A NCAC 2D .1418 - New Electric Generating Units, Large Boilers, and Large I/C Engines

This regulation is NC's NO_x SIP-Call requirement. It applies to combustion turbines, permitted after October 31, 2000, serving a generator with a nameplate capacity greater than 25 megawatts electric and selling amount of electricity.

New combined cycle combustion turbines are expected to be permitted in 2008 or after and will have a combined generating capacity of 630 MW electric. Hence, they are subject to the regulation.

NO_x emissions from these combustion turbines cannot exceed the LAER requirements of Rule 2D .0531.

The turbines will be subject to monitoring requirements under 2D .1404(d) of 15A NCAC. That is, the turbines may be subject to the continuous emission monitoring requirements under 40 CFR 75, Subpart H with such exceptions as may be allowed in 40 CFR 75, Subpart H or 40 CFR 96.

Finally, the Permittee will be required to obtain NO_x allocations for the turbines as per the procedures established in 2D .1421.

4.2.14 15A NCAC 2Q .0402 - Acid Rain Permitting Procedures

New combustion turbines are subject to the Acid Rain program requirements under the CAA. They are deemed to be "new, utility, non-peaking units" pursuant to 40 CFR 72.2. The Permittee is required to submit a separate Acid Rain permit application for these units at least 24 months before

it commences operation. The planned commencement date of the unit is January 2011. Therefore, the deadline for submittal of the Acid Rain permit application is January 2009. The Permittee will be required to obtain SO₂ allowances and track the allocated emissions using CEMs. The Permittee will also be required to accurately report NO_x emissions on an annual basis using CEMs.

SECTION 5.0
BEST AVAILABLE CONTROL TECHNOLOGY
AND
LOWEST ACHIEVABLE EMISSION RATE ANALYSIS

5.1 BACT

Each pollutant subject to PSD review must employ BACT as described in Section 4.1 above. Given the variation between emission sources, facility configuration, local airsheds, and other case-by case considerations, Congress determined that it was impossible to establish a single BACT determination for a particular pollutant or source. Economics, energy, and environmental impact are mandated in the CAA to be considered in the determination of case-by-case BACT for specific emission sources. In most instances, BACT may be defined through an emission limitation. In cases where this is impossible, BACT can be defined by the use of a particular type of control device and its achievable emission reduction efficiency. In no event can a technology be recommended which would not comply with any applicable standard of performance under 40 CFR Parts 60 and 61.

Additionally, as a result of the EPA remand involving the North County Resource Recovery project in Region IX, the effects of non-regulated PSD pollutants, such as toxic air pollutants, are to be accounted for in determining if the BACT otherwise being prescribed for a regulated pollutant still represents an appropriate level and type of control. There is no specific formula for making PSD decisions for unregulated pollutants; this is a case-by-case process involving the judgment of the reviewing authority. If the reviewing authority judges the potential environmental effects of such unregulated pollutants to be of possible concern to the public, then the final BACT decision for a regulated pollutant should address these efforts and reflect, as appropriate, the control technology beyond what might otherwise be chosen as BACT.

To assist in bringing consistency to the BACT process, the EPA has issued guidance encouraging all PSD applicants to use the "top-down" approach to BACT. NCDAQ does not

strictly adhere to EPA's top-down guidance. Rather DAQ implements BACT in strict accordance with the statutory and regulatory language. As such, DAQ's BACT conclusions may differ from those of the applicant or EPA.

In general, the top-down approach consists of five basic steps. These are:

- 1) Identify all control technologies,
- 2) Eliminate technically infeasible options,
- 3) Rank remaining control technologies by control efficiencies,
- 4) Evaluate the most effective controls and document results, and
- 5) Select BACT

The first step in this approach is a comprehensive listing of control technologies for each applicable pollutant. Step two is a demonstration of technical feasibility to ensure the technology evaluated was appropriate for the characteristic gas stream to be treated. Step three ranks the remaining control technologies by control effectiveness, including the control efficiencies (percent of pollutant removed), expected emission rate (tons per year), expected emission reduction (tons per year), economic impacts (total cost effectiveness, incremental cost effectiveness), environmental impacts (including emissions of toxic or hazardous air contaminants), and energy impacts (benefits or disadvantages). Step four is a case-by-case evaluation of energy, environmental, and economic impacts. Step five requires the selection of the most effective option not rejected as BACT for the emission source.

As indicated in Section 4.1 above, the change in emissions due to the project for PM, PM₁₀, NO_x as NO₂, and CO, will exceed their respective significance thresholds. The BACT analysis will focus on applicable control techniques for combined cycle combustion turbines and cooling tower for the above pollutants.

5.2 LAER

Pursuant to §173(a)(2) of the CAA, new major sources and existing major sources undertaking major modifications subject to nonattainment NSR must apply the state of the art emission controls that meet the LAER. LAER is based on the most stringent emission limitation in the State's SIP, or achieved in practice by the source category under review. By definition, LAER cannot be less stringent than any applicable New Source Performance Standard (Part 60).

Unlike BACT, the LAER requirement places less emphasis on economic, energy, or environmental factors. As indicated in Section 4.1 above, the change in emissions due to the project for NO_x and VOC will exceed their respective significance thresholds. The LAER analysis will focus on applicable control techniques for combined cycle combustion turbines only, as the cooling tower is not expected to emit either of these pollutants.

5.3 Previous BACT/LAER Determinations

DAQ searched the RACT/BACT/LAER Clearinghouse for the time period from 2002 to present, to identify and evaluate the current BACT and LAER determinations for both NO_x and VOC, and BACT determinations for PM/PM₁₀, CO and SO₂, for the new combined cycle combustion turbines and a cooling tower. The following is a brief summary of this search:

NO_x

There are several BACT and a few LAER determinations, which include an emission limit of 2 ppm at 15 percent O₂ using dry low-NO_x combustors and selective catalytic reduction for natural gas firing.

VOC

There are a few BACT determinations with an emission limit of 1 ppm at 15 percent O₂ using oxidation catalyst and good combustion control. In addition, there is one determination, which includes an emission limit of 0.7 ppm using good combustion control and oxidation catalyst.

PM/PM-10

Almost all of these determinations required low ash, low sulfur clean fuel, and/or good combustion control as BACT for combined cycle combustion turbines burning natural gas. There are a couple of BACT determinations, with an emission limit of 0.0005% using drift eliminators for cooling towers.

CO

There are several BACT determinations, which include an emission limit of 2 ppm at 15 percent O₂ using oxidation catalyst with one determination having the same emission limit using good combustion control. There is one determination, which includes an emission limit of 2.5 ppm at 15 percent O₂ using good combustion control.

SO₂

All of these determinations required use of low sulfur fuel consisting of pipeline quality natural gas (2 grains sulfur per 100 sft³) as BACT for SO₂.

The RBLC search summary has been included in Appendix D.

5.4 LAER Analysis for NO_x

Factors affecting NO_x formation include turbine design, ambient conditions, turbine load and fuel type. Two types of NO_x emissions from combustion turbines are of concern: thermal NO_x and fuel NO_x. Thermal NO_x generation can be explained by a chemical reaction sequence called the "Zeldovich Mechanism". This set of chemical reactions postulates that the generation of thermal NO_x is an exponential function of the flame temperature and a linear function of the

residence time of the hot gases at the flame temperature. Thus, temperature and residence time determine thermal NO_x levels in combustion turbines.

For a given fuel, because the flame temperature is a function of the equivalence ratio, the highest rate of thermal NO_x generation occurs at the equivalence ratio of 1.0, when the temperature is equal to adiabatic flame temperature. NO_x formation decreases rapidly for either fuel rich combustion (equivalence ratio greater than 1.0) or fuel lean combustion (equivalence ratio less than 1.0). Therefore, local flame stoichiometry is critical in achieving reductions in thermal NO_x.

Fuel NO_x is formed by the reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound nitrogen (although some molecular nitrogen is present). Fuel NO_x emissions in combustion turbines are inherently negligible when firing natural gas as compared to fuel oil.

Thus, essentially, all NO_x formed from natural gas combustion is thermal NO_x.

Finally, the combustion for natural gas firing is more easily controlled than for fuel oil. This leads to higher thermal NO_x and fuel NO_x contributions from oil firing.

NO_x Control Alternatives

Techniques used to reduce NO_x formation for combustion turbines during the combustion process are deemed as "combustion controls." Techniques applied downstream of the combustion zone, after NO_x formation, to reduce NO_x emissions are called as "post-combustion controls".

The following includes discussion on dry-low NO_x combustors (DLN) and catalytic reduction (SCR).

Dry Low-NO_x Combustor

A Dry low-NO_x combustor (DLN) is a combustion control technique that reduces the formation of NO_x through enhanced mixing of combustion fuel and air. DLN is currently applicable only to firing natural gas because the technology to create the required homogeneous fuel-air mixture with liquid fuels is not commercially available. The design of the combustor is a major factor in determining the amount of NO_x formation. This technology relies on establishing fuel-lean zones within the combustor and staged combustion. The first stage uses a pilot burner for flame stabilization followed by a secondary stage of multiple fuel injection nozzles where a lean premixture of fuel and air are burned in order to assure a uniform mixture and the avoidance of high temperature regions in the combustor.

The proposed GE 7FA combustion turbines include DLN-2.6 technology when firing natural gas for control of NO_x emissions. The key feature of the DLN-2.6 is the addition of sixth burner located in the center of the five existing DLN-2 burners. The DLN-2.6 will allow the NO_x reduction to 9 ppm when firing natural gas. This 9 ppm technology is a current state-of-the-art for 7FA turbines.

Selective Catalytic Reduction (SCR)

SCR is a post-combustion control technology whereby ammonia is injected into the exhaust gas upstream of a catalyst bed, and is normally used in conjunction with other combustion control(s) to achieve a higher degree of control than either technology alone can provide. The ammonia reacts with NO_x in the exhaust gas to form molecular nitrogen and water vapor. Most commercial SCR systems utilize base metal catalysts (vanadium- or titanium-based) and operate over a temperature range of approximately 500-750 °F. A given catalyst achieves effective NO_x control within a 100-200 °F temperature-window. At temperatures outside this window, the catalyst becomes ineffective and NO_x reduction decreases. Excess temperatures can permanently damage the catalyst. Also, at low temperatures unreacted ammonia can "slip" through and be emitted to the atmosphere.

SCR systems have been determined to be LAER and BACT to reduce NO_x emissions for several combined-cycle baseload installations firing natural gas or firing natural gas as the primary fuel with limited hours of fuel oil firing as backup. LAER emission levels as low as 2.0 ppm have been permitted and achieved using SCR control for NO_x.

NO_x LAER Selection

The Permittee has proposed an emission limit of 2 ppmvd at 15 percent O₂, when running with or without the duct burners, using the SCR for the first 500 hours of operation, as LAER for the combined cycle combustion turbines. Thereafter (after 500 hours of operation), the Permittee has proposed the LAER of 2.5 ppmvd at 15 percent O₂ when running with or without duct burner, using SCR. In addition, the Permittee has proposed a 24-hour rolling average basis as the compliance averaging period for the above LAER limits.

The Permittee contends that although it is expected to obtain a performance guarantee of 2 ppmvd for SCR, it does not currently have one. It adds that catalyst performance deteriorates over time and vendor guarantees are not typically for the entire life of the catalyst, and therefore, it has proposed a 2.5 ppmvd limit for NO_x emissions on a long term basis.

It should also be stated here that the Permittee has later agreed with DAQ that 2 ppmvd is a current LAER for NO_x emissions from combined cycle units burning natural gas³.

There are a total of 18 final determinations (2002-Present)⁴ in the EPA's RBLC database for NO_x emissions from combined cycle combustion turbines, which include either LAER or BACT emission limits of 2 ppmvd using DLN and SCR. See Appendix D of this report. DAQ has researched this matter further by contacting various permitting authorities for their operating

³ August 19, 2008 submittal from Scott Dial, Plant Manager, Plant Rowan County to Donald van der Vaart, Ph.D., P.E., Chief, Permitting Section, DAQ.

⁴ AZ-0038, AZ-0039, AZ-0043, AZ-0043, AZ-0047, AZ-0047, AZ-0049, AZ-0049, CA-0997, CA-1096, CA-1097, FL-0263, NV-0035, NV-0035, NV-0037, NV-0038, VA-0291, and WA-0315.

history and verification of 2 ppmvd emission limit. This investigation revealed that for five determinations (AZ-0039, CA-0997, CA-1096, CA-1097, and FL-0263, 2 LAER and 3 BACT determinations) out of 18, compliance with a 2 ppmvd emission limit was verified by various permitting agencies with operating history of 1-3 years. For one additional determination (AZ-0038), the permitting authority had revised the original emission limit of 2 ppmvd to 2.5 ppmvd for NO_x and verified it for compliance. However, this agency has stated that for new combined cycle turbine projects, their agency was issuing air permits with 2 ppmvd emission limit using SCR⁵.

Based on the above, DAQ believes that a 2 ppmvd emission limit using DLN and SCR, is currently LAER for the proposed source. In addition, DAQ deems the above limit achieved in practice on all load types (except start-up, shutdown, and malfunctions) on a long-term basis for combined cycle combustion turbines burning natural gas and operating with or without duct burner.

Thus, DAQ proposes to require a LAER of 2 ppmvd at 15 percent O₂ using DLN and SCR, on a 30-day rolling average basis, when burning natural gas for NO_x emissions for all operating loads and for both with or without duct burners scenarios. The initial compliance with the LAER limit will be verified through a stack test and continuous compliance via continuous emission monitoring systems (CEMs) for NO_x. Finally, the proposed LAER emission limit will also comply with the applicable NSPS and SIP emission standards as discussed in Section 4 above.

5.5 BACT Analysis for NO_x as NO₂

As indicated in Section 3.0 above, the County of Rowan is in attainment for the NO₂ NAAQS. In addition, emissions of NO_x as NO₂ exceed the significance threshold as discussed in Section 4.1 above. Hence, a separate analysis for BACT for NO_x as NO₂ is required for this project.

⁵ Telephone communication between Rahul Thaker of NC DAQ and Henry Krautter of AZ DEQ on 6/11/08.

Section 5.4 above adequately covers the discussion on NO_x formation and NO_x control alternatives for combined cycle combustion turbines. Those control alternatives are also applicable here for the BACT analysis for NO_x as NO₂. Please refer to Section 5.4 for details.

Unlike LAER for NO_x, the Permittee has not provided a separate BACT analysis for NO_x as NO₂ nor has proposed a BACT for these emission units.

DAQ believes that 2 ppmvd emission limit with the use of DLN and SCR satisfies the BACT as demonstrated in Section 5.4 above. DAQ also believes that BACT can be less stringent than LAER when weighing the statutory factors of energy, environment, economic, and others costs.

Based on the above, the DAQ proposes to require the BACT of 2 ppmvd at 15 percent O₂ using DLN and SCR, on a 30-day rolling average basis, when burning natural gas for NO_x (as NO₂) emissions for all operating loads and for both with or without duct burners scenarios, for the first 500 hours of operation. For the operating scenario for SCR operation after the initial 500 hours of operation, DAQ proposes to require the BACT of 2.5 ppmvd at 15 percent O₂ using DLN and SCR, on a 30-day rolling average basis, when burning natural gas for NO_x (as NO₂) emissions for all operating loads and for both with or without duct burners modes.

Initial compliance with the NO_x (as NO₂) BACT emission limits will be verified through a stack test and continuous compliance via a continuous emission monitoring systems (CEMs) for NO_x. Finally, the proposed BACT emission limits comply with the applicable NSPS and SIP emission standards as discussed in Section 4 above.

5.6 LAER Analysis for VOC

Volatile organic compounds (VOC) are formed as a result of incomplete fuel combustion. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis of the heavier hydrocarbon constituents.

VOC emissions are affected by the gas turbine operating conditions. VOC emissions are higher for gas turbines operating at low loads as compared similar gas turbines operating at higher loads. VOC emissions can also increase due to low combustion temperature, ambient conditions, insufficient residence time, and insufficient oxygen as a result of low air-to-fuel ratio or inadequate mixing (which in turn can be due to improper burner settings and/or deteriorated burner components).

Control of VOC is accomplished by providing adequate fuel residence time, mixing, and temperature in the combustion zone to ensure complete combustion. However, these factors can have an adverse impact on emissions of NO_x.

VOC Control Alternatives

The following includes discussion on "good combustion control practices" and catalytic oxidation.

Good Combustion Control Practices

Good combustion control practices rely on efficient operation of the combustion turbine. Emissions of VOCs are minimized due to better combustion efficiency through optimum design and operation of the combustion turbine. This includes proper air-to-fuel ratios, and a turbine design that provides the necessary temperature, residence time and mixing conditions in the combustion zone. As a result of economic incentives as well as air pollution concerns, manufacturers have attempted to maximize the combustion efficiency of turbines. Due to high combustion efficiency of combustion turbines (near 99 percent), VOC emissions are inherently low.

Catalytic Oxidation

Catalytic oxidation is an add-on or post-combustion control in which the turbine exhaust gases pass through a catalyst bed (typically platinum/rhodium), where hydrocarbons are oxidized to carbon dioxide and water vapor to a lesser extent. No supplementary reactant is used in conjunction with an oxidation catalyst.

Oxidation catalysts have been employed on combustion turbines for several years for both natural gas and fuel oil-firing modes.

VOC LAER Selection

The Permittee has proposed a VOC LAER of 1.4 ppmvd (as CH₄) and 2 ppmvd (as CH₄), both at 15 percent O₂, when running without duct burner and with duct burner, respectively, using good combustion control practices and catalytic oxidation. In addition, the Permittee has proposed a 3-hour average basis as the averaging period for the compliance with the above LAER limits.

There are a total of six final determinations (2002-Present)⁶ in the RBLC database for VOC emissions from the combined cycle combustion turbines, which include BACT emission limit of 0.7 to 1 ppmvd at 15 percent O₂. See Appendix D of this report for details. DAQ has researched this matter further by contacting various permitting authorities for their operating history and verification of 1 ppmvd emission limit. The research revealed that for only one determination (MN-0053) out of six, the compliance was demonstrated with the revised higher limit of 1.5 ppm (without duct burner) and 3 ppm (with duct burner), with an operational history of approximately one year. For all other determinations, the approved projects did not yet commence operation.

Based on the above, DAQ approves the 1.4 ppmvd (as CH₄) and 2 ppmvd (as CH₄), both at 15 percent O₂ on a 3-hour average basis, when running without duct burner and with duct burner, respectively, using good combustion control practices and catalytic oxidation, as LAER for the proposed combined cycle combustion turbines. Compliance with the LAER emission limit will

⁶ AZ-0043, NC-0095, NJ-0043, MN-0053, VA-0291, and VA-0291.

be verified through initial stack test. Continuous compliance with the emission limit will be verified by maintaining the 4-hour rolling average of the catalyst inlet temperature higher than 1000 °F until it establishes the minimum inlet temperature to the oxidation catalyst during stack testing for VOC.

5.7 BACT Analysis for CO

Similarly to VOC, CO is formed as a result of incomplete combustion of fuel. Control of CO is also accomplished by providing adequate fuel residence time, mixing, and temperature in the combustion zone to ensure complete combustion. These factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through flame temperature control (by dry lean pre-mix natural gas fired burners) can result in higher levels of CO emissions. Thus, a compromise is established whereby the combustion conditions are set to achieve the lowest NO_x emission rate possible while keeping CO emission rates at acceptable levels.

CO emissions from gas turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. CO control methods include exhaust gas cleanup methods such as catalytic oxidation, and front-end methods such as combustion control wherein CO formation is suppressed within the combustors.

CO Control Alternatives

The following includes discussion on "good combustion control practices" and catalytic oxidation.

Good Combustion Control Practices

Good combustion control practices rely on efficient operation of the combustion turbine. Emissions of CO are minimized due to better combustion efficiency through optimum design

and operation of the combustion turbine. This includes proper air-to-fuel ratios, and a turbine design that provides the necessary temperature, residence time and mixing conditions in the combustion zone. As a result of economic incentives as well as air pollution concerns, manufacturers have attempted to maximize the combustion efficiency of turbines. Due to high combustion efficiency of combustion turbines (near 99 percent), CO emissions are inherently low.

Catalytic Oxidation

Catalytic oxidation is an add-on or post-combustion control in which the turbine exhaust gases pass through a catalyst bed (typically platinum/rhodium), where CO is oxidized to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst.

Catalytic oxidation is considered a technically feasible option for combined cycle combustion turbines burning natural gas with control efficiency in the range of 80 to 90 percent.

Evaluation of CO Controls using Energy, Economics, and Environmental Criteria

Energy

The only significant energy impact due to operation of CO catalyst is the backpressure penalty due to pressure drop across the catalyst bed. Thus, the overall combined cycle efficiency is reduced for the combustion turbine and HRSG as some energy will have to be expended to overcome the pressure drop. The Permittee has estimated a pressure drop of 0.7 inches of water resulting in additional energy need of 1,988,520 kWh per turbine per year. The cost of the additional fuel to overcome this energy need has been taken into consideration in the economic analysis.

Economics

The Permittee has conducted a cost impact analysis for catalytic oxidation using the EPA factors.⁷ This analysis was prepared for emission reductions for two, separate cases: (i) 4,760 hours of operation without duct burners and 4,000 hours of operation with duct burners, and (ii) 8760 hours of operation without duct burners. The analysis also incorporates an assumed performance level for the CO catalyst of 2 ppmvd and 3 ppvvd for without duct burner, and with duct burner firing scenarios, respectively. The average cost effectiveness for the above cases are \$3,760 per ton of CO and \$5,674 per ton CO removed, respectively, both at 100% load.

Environmental

The main environmental impact associated with the operation of catalytic oxidation system is the disposal of spent catalyst and the potential for generation of H₂SO₄ mist emissions.

CO BACT Selection

The Permittee has proposed a BACT of 9 ppmvd and 16 ppmvd, both at 15 percent O₂, when running without duct burner and with duct burner, respectively, using good combustion control practices. In addition, the Permittee has proposed a 3-hour average basis as the compliance averaging period for the BACT limits.

It should be noted here that there are two final determinations (2002-Present)⁸ in the EPA's RBLC database for CO emissions from combined cycle combustion turbines, which include either BACT or other case-by-case determinations including emission limits of 2-2.5 ppmvd at 15 percent O₂ using good combustion control. The first determination, which is for the Georgia facility (GA-0102), includes an emission limit of 2 ppmvd for CO. The second determination for the Pennsylvania facility (PA-0189) has its original emission limit of 2.5 ppmvd revised to 6 ppmvd and the PA facility demonstrated compliance with this higher limit. Finally, there are several BACT determinations, which require CO emission rates of 8 to 8.2 ppm using good

⁷ EPA Air Pollution Control Cost Manual, 6th ed., EPA OAQPS, RTP, NC, EPA/452/B-02-001, January 2002.

⁸ GA-0102 and PA-0189.

combustion control⁹, considering the next performance level of combined cycle units without any add-on controls.

The Permittee contends that the determinations (GA-102 and PA-0189) discussed above, are for combustion turbines, that are dissimilar to the proposed turbines at Plant Rowan County: (i) Plant Rowan turbines are made by General Electric (GE) while GA and PA turbines are by Siemens-Westinghouse (SW) (suggesting that GE turbines are not as fuel efficient as SW turbines). (ii) Duct burners on Plant Rowan turbines are much larger in size as compared to GA turbines (suggesting that larger duct burners are expected to have higher CO emissions).

The Permittee also argues that GE is not able to provide a CO emission guarantee that is significantly less than 9/16 ppmvd and that it is not possible to achieve a lower emission rate of 2 ppmvd without installing oxidation catalysts.

Based on the above, DAQ believes that the cost effectiveness, associated with the catalytic oxidation in the range of \$3,760 to \$5,674 is too high for reduction of CO emissions from the proposed combustion turbines to 2-3 ppmvd from uncontrolled emission levels of 9/16 ppmvd. DAQ also believes that an 8 ppmvd emission limit using good combustion control, is a BACT for the combined cycle combustion turbines burning natural gas. Finally, DAQ believes that the above limit is achievable at all load types (except start-up, shutdown, and malfunctions) on a long-term basis.

Thus, DAQ proposes to require the BACT of 8 ppmvd at 15 percent O₂ on a 3-hour average basis, using good combustion control, when burning natural gas for CO emissions for all operating loads and operating with or without duct burners. Compliance with the BACT emission limit will be verified through the initial stack test.

5.8 BACT Analysis for PM/PM₁₀ BACT

⁹ FL-0265, FL-0263, FL-0241, AR-0070, and OK-0070.

Combustion Turbine

PM/PM-10 emissions from combustion turbines are primarily a result of inert solids contained in the fuel and water (when water injection is used for emission control) and unburned pyrolyzed hydrocarbons. These particles pass through the turbine and are emitted in the exhaust gas. Essentially all PM emissions from gas turbines are less than 1 micron in diameter and are therefore within the PM-10 range (less than 10 micron diameter).

Emissions of PM/PM-10 from combustion turbines are inherently low because they achieve high combustion efficiencies and burn clean fuels such as natural gas. Clean fuels are needed to prevent damage to the turbine blades and other high precision turbine components. Combustion turbines are designed and operated to burn the fuel as completely as possible in order to attain the highest possible thermal efficiency.

Cooling Tower

PM/PM₁₀ emissions from cooling towers are emitted via water droplets containing dissolved solids. A certain fraction of these droplets will be of a size range such that, upon evaporation in the atmosphere, a resulting particle of PM₁₀ could be liberated as an air emission. PM / PM₁₀ (which in this case is all filterable PM₁₀) is controlled by drift eliminators, which limit the number and size distribution of liquid water droplets that escape the tower (called “drift”).

PM/PM-10 Control Alternatives

Based on a review of previous BACT determinations in the RBLC, Southern Power has considered the use of low-ash/low sulfur fuel and good combustion control as PM/PM-10 BACT for the proposed combustion turbines. The Permittee has eliminated add-on controls such as fabric filters and electrostatic precipitators as control options because neither has been used on combustion turbines due to high exhaust flow rates and low particulate loading, making these devices technically infeasible.

For the cooling tower, Southern Power proposes to use state-of-the-art mist (drift) eliminators with a maximum drift rate equal to 0.0005% of the recirculated water flow to limit drift of water droplets that may contain total dissolved solids (TDS), as BACT. There are no cooling towers identified in the RBLC with specified control other than drift eliminators.

PM/PM-10 BACT Determination

NCDAQ concurs with the Permittee that use of low ash/low sulfur fuel combined with good combustion control does represent BACT for PM/PM10 emissions from the proposed turbines. These operational controls will result in PM10 BACT emission limits (front- and back-half combined) of 0.0096 lb/million Btu PM10 while firing natural gas and operating without duct burner, and 0.0099 lb/million Btu PM10 when firing natural gas and operating with duct burner. A cost analysis is not necessary because the only technically feasible option is being proposed.

The compliance period for this BACT is 3-hour average. Because the PM10 emissions due to burning of natural gas in the combustion turbines are very low, DAQ believes that performance testing is not required for PM10 emissions.

DAQ approves to require drift eliminators with an emission limit of 0.0005% drift loss as BACT for the proposed cooling tower.

Finally, the PM/PM10 BACT emission limits for the combustion turbines and cooling tower comply with the applicable SIP emission standards as discussed in Section 4 above.

5.9 BACT Analysis for SO₂ (State-only Requirement)

SO₂ emissions are produced by the combustion of sulfur-containing fuels. SO₂ emissions are very low when burning natural gas. The potential emissions of SO₂ from the two, proposed,

combustion turbines are estimated to be approximately 10.5 tons/yr, which is well below the significance threshold of 40 tons/year.

The NC SIP requirement at 15A NCAC 2D .0530(h) require new electric generating units such as the proposed combustion turbines to be equipped with BACT even if the project emissions are less than the significance threshold. This requirement is a “state-only” requirement.

SO₂ Control Alternatives

The RBLC Clearinghouse data indicates that low sulfur fuel is the only available SO₂ control alternative for combustion turbines. Southern Power proposes to use the pipeline quality natural gas with a sulfur content of 0.2 grain/100 sft³ as BACT to control SO₂ emissions. It should be mentioned here that there are no known applications of add-on control such as flue gas desulfurization (FGD) on combustion turbines and fuel treatment is not practical since sulfur is already reduced during the natural gas refinement process.

SO₂ BACT Determination

NCDAQ concurs with the Permittee that the use of pipeline quality natural gas containing 0.2 grain/100 sft³ is a BACT for control of SO₂ from the combustion turbines. Using the above sulfur content for natural gas, the SO₂ BACT emission limit can be estimated as 0.0006 lb/million Btu, on a 1-hour average basis. Compliance will be verified using the sulfur content of the natural gas in the valid purchase contract, tariff sheet, or transportation contract. SO₂ BACT emission limit complies with the applicable NSPS and SIP emission standards as discussed in Section 4 above.

5.10 BACT and LAER Summary

The following Table presents a summary consisting of LAER and BACT determinations for various pollutants for the emissions from two, combined cycle combustion turbines and a cooling tower, as proposed by DAQ for approval.

EMISSION SOURCE	POLLUTANT	EMISSION LIMITS		CONTROL TECHNOLOGY	CASE-BY-CASE BASIS
		Without Duct Burner	With Duct Burner		
Combustion Turbines (ID Nos. ES6A and ES6B)	NOx	2 ppmvd at 15% O ₂	2 ppmvd at 15% O ₂	DLN and SCR	LAER
	NOx (as NO ₂)	2 ppmvd at 15% O ₂ [First 500 hours of operation of SCR]	2 ppmvd at 15% O ₂ [First 500 hours of operation of SCR]	Same as Above	BACT
		2.5 ppmvd at 15% O ₂ [After 500 hours of operation of SCR]	2.5 ppmvd at 15% O ₂ [After 500 hours of operation of SCR]		
Combustion Turbines (ID Nos. ES6A and ES6B)	VOC (as CH ₄)	1.4 ppmvd at 15% O ₂	2 ppmvd at 15% O ₂	good combustion control and catalytic oxidation	LAER
Combustion Turbines (ID Nos. ES6A and ES6B)	CO	8 ppmvd at 15% O ₂	8 ppmvd at 15% O ₂	good combustion control	BACT
Combustion Turbines (ID Nos. ES6A and ES6B)	PM/PM10 (filterable and condensible)	0.0096 lb/million Btu	0.0099 lb/million Btu	use of low ash, low sulfur fuel and good combustion control	BACT
Cooling Tower (ID No. ES7)	PM/PM10 (filterable only)	0.0005% drift loss	0.0005% drift loss	drift eliminators	BACT
Combustion Turbines (ID Nos. ES6A and ES6B)	SO ₂	0.0006 lb/million Btu	0.0006 lb/million Btu	use of natural gas containing 0.2 grain/100 sf ³ sulfur content	BACT ["state-only" requirement]

The following Table provides a summary of emission limits that apply in order to demonstrate compliance with the National Ambient Air Quality Standards as required by 15A NCAC 2D .0530 and 40 CFR 51.166(k):

EMISSION SOURCE	POLLUTANT	EMISSION LIMITS			
		Annual tons/yr ^a	per 24-hour lbs	per 8-hour lbs	per 1-hour lbs
Combustion Turbines (ID Nos. ES6A and ES6B)	nitrogen oxides (as nitrogen dioxide)	168.8	-	-	-
	particulates/PM-10 (filterable and condensable)	-	1089.6	-	-
	carbon monoxide	-	-	671.2	83.9

^a Tons per consecutive 12-month period based on a maximum 4,000 operating hours of duct firing and 4,760 hours of operation without duct firing in each combustion turbines (ID Nos. ES-6A and ES-6B).

SECTION 6.0
AIR QUALITY IMPACT ANALYSIS

6.0 Introduction

The NSR modeling analysis described in this section was conducted in accordance with all applicable requirements. The modeling analysis references various sources, including the Draft October 1990 EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Non-attainment Area Permitting which will herein be referred to as the NSR Workshop Manual. The NSR Workshop Manual is an EPA document describing non-binding NSR policy and is relied upon only to the extent that portions of its content are consistent with NCDAQ policy.

A summary of the modeling results is presented in the section NSR Air Quality Modeling Result Summary. A detailed description of the modeling and modeling methodology is described below.

6.1 Project Description / Significant Emission Rate (SER) Analysis

Southern Power plans the installation and operation of two new General Electric (GE) 7FA natural gas-fired combustion turbine generators (CTGs) operating in combined-cycle mode, two supplementary fired heat recovery steam generators, one reheat condensing steam turbine generator, and one cooling tower. This will potentially increase nominal generating capacity by approximately 630 Megawatt (MW) at the facility for a total of 1700 MW. PM₁₀, VOC, NO_x, and CO emissions shown in Table 6.1-1 below exceeded their respective PSD Significant Emission Rate (SER) and were evaluated as described in the preliminary impact air quality analysis section.

Table 6.1-1 Potential New CTG Increase

Pollutant	Annual Approx Emission Rate tons/yr	Significant Emission Rate tons/yr
NO_x	139.75	40

PM10	181	15
SO₂	10.5	40
CO	519.5	100
VOC's	45	40

1. Annual CT emissions are based on 8760 per year operations.
2. Cooling tower will operate at 8760 hours per year.

6.2 Preliminary Impact Air Quality Modeling Analysis

An air quality preliminary impact analysis was conducted for the pollutants exceeding the corresponding SER. The modeling results were then compared to applicable Significant Impact Levels (SILs) as provided in the NSR Workshop Manual to determine if a full impact air quality analysis would be required for that pollutant.

The Southern Power facility is located near Salisbury, North Carolina, in Rowan County. It is located in the central piedmont area with predominantly rolling terrain and is generally agricultural, industrial, and forestland. For modeling purposes, the area is classified rural based on the land use type scheme established by Auer 1978.

Southern Power evaluated the pollutant significant emissions using the EPA AERMOD model and five years (1988-1992) of National Weather Service (NWS) surface (Charlotte, NC) and upper air (Greensboro, NC) meteorological data. Modeling was initially conducted for 5 CT operating loads (Power augmentation, 100% load w/duct burner (DB), 100% load w/o DB, 75% load and 50 % load) and 3 ambient temperatures (95 deg F, 65 deg F, 0 deg F). Full terrain elevations were included as were normal regulatory defaults and representative land use data. The receptor grid began at the fence line and extended outwards to 20 kilometers at 100-meter intervals. Maximum potential emission rates were then modeled to determine the maximum (H1H) impacts for each pollutant and pollutant averaging period. The results shown in Table 2 indicate that (H1H) impact for each pollutant and pollutant averaging period was below the applicable Class II SIL; subsequently, no further modeling was required.

Table 6.2-1 Class II Significant Impact Results (ug/m³)

Pollutant	Averaging Period¹	Facility maximum Impact	Class II Significant Impact
NO _x	Annual	.51	1
PM10	Annual	.64	1
	24-hour	4.38	5
CO	8-hour	17.51	500
	1-hour	50.34	2000

6.3 Non Regulated Pollutant Impact Analysis (North Carolina Toxics)

As part of the BACT determination process, the NCDAQ has the discretion to evaluate the impacts of non-regulated pollutants resulting from the application of the various emission control candidates. North Carolina has a "state-only" air toxics program and when appropriate the NCDAQ uses the guidelines in 15A NCAC 2D .1100 to evaluate the impacts. It is important to note that this non-regulated analysis is not an applicability trigger for the air toxics program per se.

For the purpose of further evaluating the environmental impacts of the BACT/LAER candidate technologies, the Permittee modeled ammonia and sulfuric acid mist resulting from the application of SCR and VOC catalyst. This modeling was performed using AERMOD with the same receptor array and meteorology as in the preliminary impact air quality analysis. Although this analysis is focused on the impacts from the modification, for conservatism, the model included emissions not only from the modification, but also from all sources at the facility. The resulting ambient impacts were demonstrated to be below the NC Acceptable Ambient Levels (AAL). The maximum concentrations as shown in Table 6.3-3 occurred along the fence line.

Table 6.3-1 Toxics Modeling Results

Pollutant	Averaging Period	Max Impact (ug/m³)	AAL	Percent of AAL
Ammonia	1-hr	13	2700	<1
Sulfuric acid	1-hr	18.21	100	18.21

mist	24-hr	4.51	12	37.6
------	-------	------	----	------

6.4 Additional Impact Analysis

Additional impact analyses were conducted for growth, soils and vegetation, and visibility impairment.

6.4.1 Growth Impacts

The Permittee does not expect this project to cause a significant population growth increase in the area that has been a steadily growing region since 1977. There are sufficient employable residents for the small job growth being created.

6.4.2 Soils and Vegetation

The facility is located in the Western Piedmont of North Carolina. The local geography consists of rolling terrain with a mix of forests, pasture lands and agricultural crops. As demonstrated in the preliminary impact air quality analysis analyses, the facility pollutant impacts were below the established standards. Southern Power contends that these standards are conservative and were inclusive of impacts on soils and vegetation when they were established. NCDAQ agrees.

6.4.3 CLASS II Visibility Impairment Analysis

A Level 1 visibility impairment analysis was performed using the EPA VISCREEN model to demonstrate screening criteria were not exceeded in any CLASS II areas that are designated as special visibility protection areas. With background visibility set to 80km, the facility determined that the screening visibility parameter thresholds of perceptibility (Delta E) and plume contrast (Cp) of 3.004 and .031 respectively did not exceed the established thresholds of 3.09 and .05 beyond 50 km. Within that radius, there are no special protected visibility areas, thus no further visibility analysis was required.

6.5 Class I Area - Additional Requirements

The closest Class I area to the facility site is the Linville Gorge Wilderness Area located 125 km to the northwest. A Class I area SIL analysis was conducted as described below.

6.5.1 CLASS I SIL Analysis

The CALPUFF model was used to evaluate the facility NO_x and PM₁₀ emissions for impacts at the Linville Gorge Wilderness Area. The modeling was conducted using the 4 km, VISTAS-produced, 3-year (2001-2003) meteorology dataset and a receptor grid within the Class I area as defined by the National Park Service. The modeling results as shown in Table 4 indicate the facility NO_x and PM₁₀ impacts were below the established Class I SILs; subsequently, no Class I increment modeling was required.

Table 6.5.1-1 Class I Significant Impact Results (ug/m³)

Pollutant	Averaging Period	Linville Gorge Class I area SIL	Class I Maximum Impact	% of SIL
NO _x	Annual	.1	.000632	<1
PM ₁₀	24-hr	.32	.0412	12.8
	Annual	.16	.00146	<1

6.5.2 Class I Regional Haze Impact Analysis

The Division of Air Quality (DAQ) conducted a conference call with Mr. Bill Jackson of the US Forest Service to determine if the NO_x and PM₁₀ emission increases would require a CALPUFF modeling assessment for Regional haze impacts that would adversely affect the visibility (delta-deciview (dv)) or deposition (kg/ha/yr) threshold at the Linville Gorge National Wilderness

Area. Based on low emission increases, Mr. Jackson requested no analysis for either visibility or deposition for this Class I area.

6.6 NSR Air Quality Modeling Result Summary

Based on the PSD air quality ambient impact analysis, the proposed project will not cause or contribute to any violation of the Class I or Class II PSD increments, NAAQS, or any FLM AQRVs. A summary of the modeling results is presented below.

TABLE 6.6-1 SOUTHERN POWER COMPANY PSD AIR QUALITY MODELING RESULTS						
SER Evaluation						
Pollutant	Annual E/R (Tons)	SER (Tons/yr)				
NO _x	169	40				
PM ₁₀	185	15				
SO ₂	10.5	40				
CO	520.5	100				
VOC's	45	40				
H ₂ SO ₄	3.05	7				
Class II Area SIL Analysis						
Pollutant	Averaging Period	Maximum Impact (ug/m ³)	SIL (ug/m ³)			
NO _x	Annual	.51	1			
PM ₁₀	Annual	.64	1			
	24-hour	4.38	5			
CO	8-hour	17.51	500			
	1-hour	50.34	2000			
NC Air Toxics Modeling Results						
Pollutant	Averaging Period	Maximum Impact (ug/m ³)	AAL (ug/m ³)	% AAL		
Ammonia	1-hour	13	2700	<1		

Sulfuric Acid Mist	1-hour	18.21	100	18.21		
	24-hour	4.51	12	37.6		
Class 1 Area SIL Analysis						
Pollutant	Averaging Period	Maximum Impact		EPA SIL	% SIL	
		Linville Gorge				
NO _x	Annual	.000632		0.1	<1	
PM ₁₀	Annual	.00146		0.16	12.8	
	24-hour	.0412		0.32	<1	

SECTION 7.0
ADDITIONAL REQUIREMENTS FOR NAA NSR

In addition to the control technology requirement in the form of LAER (as discussed in Section 5 above), the Permittee is required to satisfy the remaining requirements of Section 173 of the Clean Air Act (CAA) before the NAA NSR permit can be issued for the proposed project: emissions offsets, alternatives analysis, and compliance demonstration.

7.1 Emissions Offsets

As stated in Section 1.0 above, this project is subject to NAA NSR requirements for both NO_x and VOC emissions.

Pursuant to Section 173(a)(1)(A) and (c)(1) of the Clean Air Act (CAA), the Permittee is required to provide demonstration that sufficient offsetting emissions have been obtained from the same facility or other facilities in the same non-attainment area before the commencement of operation of the proposed equipment.

The Plant Rowan facility is located in Rowan County, NC, which is part of the Charlotte-Gastonia-Rock Hill, NC-SC non-attainment area for ozone, as per 40 CFR 81.334. This area has been classified under Subpart 2 of Part D of the CAA as "moderate". Hence, as per 15A NCAC 2Q .0531 "Sources in Non-attainment Area" and Appendix S to 40 CFR 51 "Emission Offset Interpretive Ruling", the Permittee is required to obtain offsets (actual emissions reductions) for emissions increases of both NO_x and VOC at a ratio of at least 1.15 (reductions) to 1 (increases).

The estimated emission increases for the project are approximately 140 tons per year of NO_x and 45 tons per year of VOC, respectively, based on the proposed LAER emission limits in Section 5 above. Thus, the Permittee will be required to obtain NO_x and VOC offsets of 161 tons and 52 tons, respectively, before the commencement of operation of the proposed equipment. The air

permit will include this requirement to obtain offsets as discussed above for both NO_x and VOC as federally enforceable.

7.2 Alternative Analysis

Pursuant to §173(a)(5) of CAA, the Permittee is required to submit an analysis of alternative sites, sizes, production processes, and environmental control techniques demonstrating that benefits of the proposed project outweigh the environmental and social costs imposed as a result of its location construction, or modification.

Alternative Sites

The Permittee has conducted an alternative siting analysis using the following criteria: proximity and availability to large electric transmission lines, sufficient availability of natural gas supply, existing character of the site and surrounding area (i.e., developed, industrial, etc.), proximity to existing logistical support resources, feasibility of completing construction in time for the planned commercial operation in January 2011, and overall environmental impacts.

The Permittee currently owns two sites in North Carolina: the existing site where Plant Rowan County is located and another in Cleveland County.

The existing Plant Rowan site is at an elevation of 730 feet above mean sea level and is not located in any designated flood zone. There are no known wetlands, estuaries, critical habitats, historic or culturally significant areas on or near the proposed project footprint. Since Plant Rowan County was originally designed and constructed to accommodate an additional combined cycle block (i.e. 2 combined cycle combustion turbines and one steam turbine), the site already contains all the necessary infrastructure, making it an ideal site for the proposed new combined cycle block. The City of Salisbury, under contract with Plant Rowan County, provides water for plant operations. In addition, Plant Rowan County currently has access to a plentiful natural gas fuel supply and experienced plant personnel. Finally, there is sufficient capacity under the

existing infrastructure contracts for the needs associated with the proposed project (i.e., no changes to contracts or additional new contracts will be necessary to support the new combined cycle block).

In contrast, as per the Permittee, the site in Cleveland County does not currently have sufficient infrastructure to support a new combined-cycle block. First, the Cleveland County site does not have ready access to a water supply that would be needed to support the project. In order to bring a sufficient amount of water to the Cleveland County site, Southern Power would have to construct a nine-mile pipeline, some portion of which may be through wetlands. In addition, the Cleveland County site does not currently contain the infrastructure needed for the discharge of wastewater from the proposed project. In contrast, sufficient wastewater discharge infrastructure has already been permitted, constructed, and is currently in use at Plant Rowan County.

Because Plant Rowan County has superior infrastructure needed for an additional combined-cycle block, and because the construction of the additional infrastructure at the Cleveland County site would require additional time, expense, and would perhaps involve other impacts to the surrounding area, Plant Rowan County was chosen as the best site for the new combined cycle block.

Alternative Size

In order to prepare for future electrical generation needs, public utilities and electric membership cooperatives in North Carolina have solicited Requests for Proposals for more than 1,000 MW of additional electrical generation capacity beginning in approximately 2011. The proposed project is designed to meet a portion of these needs.

As stated in other Sections of this report, the proposed project will consist of one 2-on-1 combined-cycle block with a nominal capacity of 630 MW. As also mentioned above, Plant Rowan County was originally designed and constructed to accommodate and support an additional combined-cycle block of this size. Therefore, the Southern Power believes that the

proposed project size is appropriate for the application and would best satisfy the intermediate power needs in the region.

Alternative Production Processes

Electric power can be produced in many different ways. Renewable forms of electricity produced in the form of hydroelectric, wind, biomass, solar, and fuel cells are considered emerging technologies. However, these forms of energy are not yet able to provide the electricity at a level of reliability and efficiency that will be achieved by the proposed project. The solid fuel generation projects, such as pulverized coal projects or integrated gasification combined-cycle (IGCC), are much larger and more complex projects, requiring greater amounts of cooling water per kilowatt, and can result in additional environmental impacts not associated with gas-fired units proposed for this project. Finally, the IGCC power production has not yet been evaluated on a long-term basis or at the size of the proposed project.

As such, combined-cycle combustion, which will fire natural gas exclusively using the existing infrastructure, represents the best production process for the proposed project.

Alternative Environmental Control Techniques

A detailed analysis on environmental controls for the proposed project including the DAQ proposed LAER and BACT, as applicable, for different pollutants, is included in Section 5.0 above. DAQ believes that these proposed emission limitations do represent the lowest emissions rates achieved in practice with the required control technologies, which can be achieved on a long-term basis at the present time. In addition, the offsets the Permittee will obtain to meet the non-attainment NSR requirements for NO_x and VOCs, will ensure a net decrease in NO_x and VOC emissions for the Charlotte-Gastonia-Rock Hill, NC-SC ozone nonattainment area. Prior to commencing operation, NO_x and VOC emissions will be offset at a ratio of 1.15 to 1, which is expected to result in a net reduction of 21 tpy of NO_x emissions and 7 tpy of VOC emissions.

The Permittee contends that no other alternative would be more protective of human health and the environment while continuing to achieve its goal of providing a reliable supply of efficient electricity production for North Carolina residents. The use of natural gas to power the combined cycle turbines will result in very low emissions per kilowatt of electricity generated. The proposed combined-cycle block has been designed to minimize adverse environmental impacts and will meet or exceed all applicable environmental regulations.

Conclusions on Alternative Analysis

The alternatives analysis demonstrates that the benefits of the proposed project significantly outweigh the environmental and social costs imposed as a result of its location or construction.

7.3 Compliance Demonstration

Pursuant to §173(a)(4) of the CAA, the Permittee is required to demonstrate that all major stationary sources owned or operated by it (or by any entity controlling, controlled by, or under common control with it) in the State (i.e., NC) are subject to the emissions limitations and are in compliance, or in a schedule for compliance, with all applicable emission limitations and standards under the CAA.

Southern Power is the owner and operator of only one major source in North Carolina: Plant Rowan County. This facility is currently in compliance with all applicable Clean Air Act requirements and there are no pending or final determinations of noncompliance at the facility. Therefore, it is concluded that all of the major stationary sources owned or operated by Southern Power are in compliance with all applicable requirements for purposes of this demonstration.

APPENDIX A
Sample Emission Calculations

APPENDIX B
Draft Permit

APPENDIX C
Public Notice

APPENDIX D
RBLC NCDAQ Search Summary

APPENDIX E
Application