

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

**PREVENTION OF SIGNIFICANT DETERIORATION  
PRELIMINARY DETERMINATION**

**FOR**

**SIX SIMPLE CYCLE COMBUSTION TURBINES  
AND  
ASSOCIATED EQUIPMENT**

**AT**

**CLEVELAND COUNTY  
SOUTHERN POWER COMPANY  
GROVER, CLEVELAND COUNTY  
NORTH CAROLINA**

**MARCH, 2009**

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Preliminary Determination &  
Public Notice

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Preliminary Determination &  
Public Notice

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## Fact Sheet

### Applicant:

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- Southern Power Company, Grover, NC, submitted a permit application under Prevention of Significant Deterioration (PSD) to the North Carolina Division of Air Quality (NCDAQ), on February 14, 2008 to construct a new electrical power generating facility, known as Cleveland County Generating Facility (CCGF), in Grover, Cleveland County, North Carolina.
- 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.
- CCGF is a Greenfield facility that is classified as a major stationary source under 40 CFR 51.166 (b)(1)(i). A source is considered major if it belongs to any one of the 28 source categories listed in the PSD regulations with the potential to emit 100 tons per year (tpy) or more of any pollutant regulated under the Clean Air Act (CAA), or if it is any other stationary source with the potential to emit 250 tpy or more of any regulated pollutant. The proposed electrical power generating facility comprised of simple-cycle turbines is not one of the 28 sources. CCGF is classified as a major stationary source because the facility will have the potential to emit greater than 250 tpy of nitrogen oxides (as NO<sub>2</sub>) and carbon monoxide (CO) after control.
- The application includes a request to construct and operate an electrical power generating facility consisting of six dual fuel simple cycle combustion turbines (nominally 190 MW each), one emergency diesel generator, one fire water pump engine, one fuel gas heater, and two fuel oil storage tanks. As proposed, potential emissions from the generating facility will be 235 tpy each of PM/PM<sub>10</sub>, 1,319 tpy of NO<sub>x</sub>, 450 tpy of CO, 62 tpy of VOC, 14 tpy of SO<sub>2</sub>, and 2.1 tpy of sulfuric acid mist [H<sub>2</sub>SO<sub>4</sub> mist]. The potential emission rates for PM, PM<sub>10</sub>, NO<sub>x</sub>, CO, and VOC exceed their respective PSD significance thresholds of 25 tpy, 15 tpy, 40 tpy, 100 tpy, and 40 tpy.
- NCDAQ proposes the following Best Available Control Technology (BACT) emission limits and control techniques for the proposed project equipment:

<b>Emission Source</b>	<b>Pollutant</b>	<b>Fuel</b>	<b>Emission Limits<sup>1 to 4</sup></b>	<b>Control Technology</b>
six natural gas/No. 2 fuel oil-fired simple cycle combustion turbines <b>(ID Nos. ES1 through ES6)</b>	NO <sub>x</sub> (as NO <sub>2</sub> )	natural gas	9 ppmvd <sup>2</sup> at 15% O <sub>2</sub> [24-hour average] <sup>3</sup>	dry-low NO <sub>x</sub> combustors
		fuel oil	42 ppmvd <sup>2</sup> at 15% O <sub>2</sub> [24-hour average] <sup>3</sup>	water injection
	CO <sup>4</sup>	natural gas	4 ppmvd at 15% O <sub>2</sub> at 70 to 100% load	good combustion control practices
			10 ppmvd at 15% O <sub>2</sub> at 60 to <70% load	
		fuel oil	10 ppmvd at 15% O <sub>2</sub> at 90 to 100% load	good combustion control practices
			20 ppmvd at 15% O <sub>2</sub> at 80 to <90% load 30 ppmvd at 15% O <sub>2</sub> at 70 to <80% load	
	VOC (as CH <sub>4</sub> ) <sup>4</sup>	natural gas	1 ppmvd at 15% O <sub>2</sub> at 70 to 100% load	good combustion control practices
			5 ppmvd at 15% O <sub>2</sub> at 60 to <70% load	
		fuel oil	10 ppmvd at 15% O <sub>2</sub>	good combustion control practices
	PM/PM <sub>10</sub> (filterable and condensable)	natural gas	0.0083 lb/million Btu	good combustion control practices and use of pipeline quality natural gas containing a maximum of 0.2 grain per 100 square feet sulfur content
fuel oil		0.0646 lb/million Btu	good combustion control practices and use of ultra-low sulfur No. 2 fuel oil containing a maximum of 0.0015% by weight (15ppm) sulfur content	
emergency generator <b>(ID No. ES7)</b>	NO <sub>x</sub> and VOC combined	fuel oil	4.7 g/hp-hr	ignition timing retard and low NO <sub>x</sub> engine design
	CO	fuel oil	2.5 g/hp-hr	good combustion control practices
	VOC (as CH <sub>4</sub> )	fuel oil	0.29 g/hp-hr	good combustion control practices and annual use limits
	PM/PM <sub>10</sub> (filterable and condensable)	fuel oil	0.15 g/hp-hr	use of ultra-low sulfur No. 2 fuel oil containing a maximum of 0.0015%

<b>Emission Source</b>	<b>Pollutant</b>	<b>Fuel</b>	<b>Emission Limits<sup>1 to 4</sup></b>	<b>Control Technology</b>
				by weight (15ppm) sulfur content and annual use limits
emergency fire water pump engine <b>(ID No. ES8)</b>	NO <sub>x</sub> (as NO <sub>2</sub> )	fuel oil	4.4 g/hp-hr	ignition timing retard, low NO <sub>x</sub> engine design, and good combustion control
	CO	fuel oil	2.6 g/hp-hr	good combustion control practices
	VOC (as CH <sub>4</sub> )	fuel oil	1.1 g/hp-hr	good combustion control practices
	PM/PM <sub>10</sub> (filterable and condensable)	fuel oil	0.23 g/hp-hr	use of ultra-low sulfur No. 2 fuel oil containing a maximum of 0.0015% by weight (15ppm) sulfur content
gas heater <b>(ID Nos. ES9)</b>	NO <sub>x</sub> (as NO <sub>2</sub> )	natural gas	0.10 lb/million Btu	low NO <sub>x</sub> burners and good combustion control practices
	CO	natural gas	0.08 lb/million Btu	good combustion control practices
	VOC (as CH <sub>4</sub> )	natural gas	0.005 lb/million Btu	good combustion control practices
	PM/PM <sub>10</sub> (filterable and condensable)	natural gas	0.0076 lb/million Btu	pipeline quality natural gas

1. BACT emission limits shall apply to each source (ID Nos. ES1 through ES9) at all times except during the following: Emissions resulting from start-up, shutdown or malfunction above those listed in the table above are permitted provided that optimal operational practices are adhered to and periods of excess emissions are minimized. For the simple cycle combustion turbines (ID Nos. ES1 through ES6), periods of excess emissions due to start-up and/or shutdown or operation below 60% load on natural gas / 70% load on fuel oil shall not exceed two hours in any 24-hour block period beginning at midnight. Start-up is defined as the period from initial firing to 60% load on natural gas / 70% load on fuel oil. Shutdown is defined as the period from 60% load on natural gas / 70% load on fuel oil to flame out.
2. ppmvd = parts per million by volume on a dry basis at 15% O<sub>2</sub>.
3. 24-hour rolling average is calculated using only actual operating hours (periods of zero emissions when not operating are not included).
4. Compliance with the BACT limits shall be based on a 3-run average of a stack test. Any use of continuous emission monitoring systems data for demonstrating compliance with BACT for any pollutants will require reevaluation of applicable BACT limits.

## SECTION 1.0 INTRODUCTION

Southern Power Company (“Southern Power”) has submitted to the North Carolina Division of Air Quality (NCDAQ) a permit application (2300372.08A), under the Prevention of Significant Deterioration (PSD) and Title V requirements of the Clean Air Act (CAA), for the construction and operation of six dual-fuel fired simple cycle internal combustion turbines (ID Nos. ES1, ES2, ES3, ES4, ES5 and ES6), one emergency generator (ID No. ES7), one emergency fire-water pump engine (ID No. ES8), one natural gas-fired gas heater (ID No. ES9), and two fuel storage tanks (ID Nos. ES10 and ES11) at a proposed plant site in Grover, Cleveland County, North Carolina, known as the Cleveland County Generating Facility (CCGF). The permit application is being processed in accordance with the requirements in 15A NCAC 2D .0530 “Prevention of Significant Deterioration” and 15A NCAC 2Q .0500 “Title V Procedures.”

Under the PSD requirements, all new or modified major stationary sources of air pollutants regulated under the CAA must undergo a preconstruction review consistent with Section 165 of the Act prior to beginning actual construction. A major stationary source is defined as any one of 28 named source categories with the potential to emit 100 tons per year (tpy) or more or any other stationary source with the potential to emit 250 tpy or more of any CAA regulated pollutant. CCGF is not one of the 28 listed source categories. Hence, the major source threshold is 250 tpy of any regulated pollutant. As proposed, CCGF will have the potential to emit greater than 250 tpy each of nitrogen oxides (NO<sub>x</sub>) and carbon monoxide (CO). Therefore, CCGF is considered a PSD major stationary source as defined by 40 CFR 51.166 (b)(1)(i)(b). Under PSD, a source that is major for NO<sub>x</sub> is also considered major for ozone.

As a major stationary source, CCGF is required to meet certain review requirements for each pollutant resulting from the proposed project, which may be emitted greater than the PSD significance level. Potential emissions from CCGF are 235 tpy of PM/PM<sub>10</sub>, 1,319 tpy of NO<sub>x</sub>, 450 tpy of CO, 62 tpy of VOC, 14 tpy of SO<sub>2</sub>, and 2 tpy of sulfuric acid mist [H<sub>2</sub>SO<sub>4</sub> mist]. Potential PM, PM<sub>10</sub>, NO<sub>x</sub>, CO, and VOC emissions exceed their respective PSD significance thresholds of 25 tpy, 15 tpy, 40 tpy, 100 tpy, and 40 tpy. Thus, the project is subject to review and processing under the NCAC 2D .0530 "Prevention of Significant Deterioration" for emissions of PM, PM<sub>10</sub>, NO<sub>x</sub>, CO, 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.

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

**Table 1-1 Best Available Control Technology**

<b>Emission Source</b>	<b>Pollutant</b>	<b>Fuel</b>	<b>Emission Limits<sup>1 to 4</sup></b>	<b>Control Technology</b>
six natural gas/No. 2 fuel oil-fired simple cycle combustion turbines <b>(ID Nos. ES1 through ES6)</b>	NO <sub>x</sub> (as NO <sub>2</sub> )	natural gas	9 ppmvd <sup>2</sup> at 15% O <sub>2</sub> [24-hour average] <sup>3</sup>	dry-low NO <sub>x</sub> combustors
		fuel oil	42 ppmvd <sup>2</sup> at 15% O <sub>2</sub> [24-hour average] <sup>3</sup>	water injection
	CO <sup>4</sup>	natural gas	4 ppmvd at 15% O <sub>2</sub> at 70 to 100% load	good combustion control practices
			10 ppmvd at 15% O <sub>2</sub> at 60 to <70% load	
		fuel oil	10 ppmvd at 15% O <sub>2</sub> at 90 to 100% load	good combustion control practices
			20 ppmvd at 15% O <sub>2</sub> at 80 to <90% load	
	VOC (as CH <sub>4</sub> ) <sup>4</sup>	natural gas	1 ppmvd at 15% O <sub>2</sub> at 70 to 100% load	good combustion control practices
			5 ppmvd at 15% O <sub>2</sub> at 60 to <70% load	
		fuel oil	10 ppmvd at 15% O <sub>2</sub>	good combustion control practices
	PM/PM <sub>10</sub> (filterable and condensable)	natural gas	0.0083 lb/million Btu	good combustion control practices and use of pipeline quality natural gas containing a maximum of 0.2 grain per 100 square feet sulfur content
fuel oil		0.0646 lb/million Btu	good combustion control practices and use of ultra-low sulfur No. 2 fuel oil containing a maximum of 0.0015% by weight (15ppm) sulfur content	
emergency generator <b>(ID No. ES7)</b>	NO <sub>x</sub> and VOC combined	fuel oil	4.7 g/hp-hr	ignition timing retard and low NO <sub>x</sub> engine design
	CO	fuel oil	2.5 g/hp-hr	good combustion control practices

<b>Emission Source</b>	<b>Pollutant</b>	<b>Fuel</b>	<b>Emission Limits<sup>1 to 4</sup></b>	<b>Control Technology</b>
	VOC (as CH <sub>4</sub> )	fuel oil	0.29 g/hp-hr	good combustion control practices and annual use limits
	PM/PM <sub>10</sub> (filterable and condensable)	fuel oil	0.15 g/hp-hr	use of ultra-low sulfur No. 2 fuel oil containing a maximum of 0.0015% by weight (15ppm) sulfur content and annual use limits
emergency fire water pump engine (ID No. ES8)	NO <sub>x</sub> (as NO <sub>2</sub> )	fuel oil	4.4 g/hp-hr	ignition timing retard, low NO <sub>x</sub> engine design, and good combustion control
	CO	fuel oil	2.6 g/hp-hr	good combustion control practices
	VOC (as CH <sub>4</sub> )	fuel oil	1.1 g/hp-hr	good combustion control practices
	PM/PM <sub>10</sub> (filterable and condensable)	fuel oil	0.23 g/hp-hr	use of ultra-low sulfur No. 2 fuel oil containing a maximum of 0.0015% by weight (15ppm) sulfur content
gas heater (ID Nos. ES9)	NO <sub>x</sub> (as NO <sub>2</sub> )	natural gas	0.10 lb/million Btu	low NO <sub>x</sub> burners and good combustion control practices
	CO	natural gas	0.08 lb/million Btu	good combustion control practices
	VOC (as CH <sub>4</sub> )	natural gas	0.005 lb/million Btu	good combustion control practices
	PM/PM <sub>10</sub> (filterable and condensable)	natural gas	0.0076 lb/million Btu	pipeline quality natural gas

1. BACT emission limits shall apply to each source (ID Nos. ES1 through ES9) at all times except during the following: Emissions resulting from start-up, shutdown or malfunction above those listed in the table above are permitted provided that optimal operational practices are adhered to and periods of excess emissions are minimized. For the simple cycle combustion turbines (ID Nos. ES1 through ES6), periods of excess emissions due to start-up and/or shutdown or operation below 60% load on natural gas / 70% load on fuel oil shall not exceed two hours in any 24-hour block period beginning at midnight. Start-up is defined as the period from initial firing to 60% load on natural gas / 70% load on fuel oil. Shutdown is defined as the period from 60% load on natural gas / 70% load on fuel oil to flame out.
2. ppmvd = parts per million by volume on a dry basis at 15% O<sub>2</sub>.
3. 24-hour rolling average is calculated using only actual operating hours (periods of zero emissions when not operating are not included).
4. Compliance with the BACT limits shall be based on a 3-run average of a stack test. Any use of continuous emission monitoring systems data for demonstrating compliance with BACT for any pollutants will require reevaluation of applicable BACT limits.

The source impact and additional impact analysis, 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.

### **1.1 Preliminary Determination**

The NCDAQ Permits Section staff has conducted a preconstruction review of Southern Power's application and made a preliminary determination that the proposed project will comply with all applicable North Carolina air quality regulations including the PSD requirements. Therefore, the NCDAQ proposes to issue an air permit for the new facility described in Section 1 above, with specific permit conditions and emission limits. This approval is contingent upon the following findings:

- A demonstration that the 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 increments will not be exceeded 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, 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 exceed Class I increment levels.

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, potential emissions, and a description of the site location. Section 4 provides 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 analysis. Section 6 presents the results of the air quality analysis. 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

The proposed site where Southern Power plans to locate the Cleveland County Generating Facility is a Greenfield site. Southern Power currently owns and operates more than 6,700 megawatts (MW) of generation assets in the Southeast including a 925 MW plant in Rowan County, North Carolina. Plant Rowan consists of three simple cycle combustion turbines and two combined cycle combustion turbines.

##### 2.1.2 Proposed Air Emission Sources

Southern Power is proposing to construct and operate a gas turbine power plant consisting of six natural gas/No. 2 fuel oil-fired simple-cycle combustion turbines (ID Nos. ES1, ES2, ES3, ES4, ES5, and ES6), one emergency generator (ID No. ES7), one emergency fire-water pump (ID No. ES8), one natural gas-fired heater (ID No. ES9), and two fuel storage tanks (ID Nos. ES10 and ES11) at the proposed CCGF site. This turbine power facility will be capable of producing nominally 1,140 MW of electricity. Total annual operation of the facility will be limited to 12,000 full load equivalent turbine hours per calendar year during which time the turbines will be fueled by distillate fuel for up to 6,000 turbine hours. Fuel oil usage will also be restricted on a daily basis.

The proposed facility is classified under the Standard Industrial Classification (SIC) code system as 4911 (Electric Services) and under the North American Industrial Classification System (NAICS) as 221112 (Fossil Fuel Electric Power Generation).

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

##### Gas Turbines

Gas turbine power plants are based on aircraft jet engine technology. They consist of a gas compressor, fuel combustors and a gas expansion turbine. Air is compressed in the gas compressor and energy is added to the compressed air by combusting liquid or gaseous fuel in the combustor. The hot, compressed air is expanded through the gas turbine, which drives both the compressor and an electric power generator. The proposed project includes the installation of six heavy-duty frame Siemens SGT6-5000F dual fueled simple-cycle combustion turbine generators (CTGs), each with a nominal electrical generating capacity of 190 to 200 MW. The fuel will consist of pipeline quality gas and ultra low-sulfur distillate fuel oil. The maximum heat input for each of these turbines is 2210 million Btu per hour firing natural gas and 2129 million Btu per hour firing ULSD fuel oil.

The gas turbine is the main component of each proposed simple-cycle power system. According to the applicant, “First, air is filtered, cooled, and compressed in a multiple-stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine’s combustion chamber. Lean pre-mix dry low NO<sub>x</sub> combustors minimize NO<sub>x</sub> formation during natural gas combustion. During period of distillate fuel oil operation, a NO<sub>x</sub> reduction water injection system is utilized to minimize NO<sub>x</sub> formation. 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 electric power generator.” The simple-cycle combustion turbine differs from a combined-cycle design in that it has no provision for waste heat recovery. The lack of heat recovery allows the turbine to be turned on and off within minutes and respond quickly to peak loading demands but generally lowers thermal efficiency by 20% or more.

## **SGT6-5000F**



### **Siemens SGT6-5000F Technical Features:**

- 190 to 200 MW Nominal Power Output
- 38.1% Efficiency
- 8,953 Btu/KWh Heat Rate
- 16 can-type combustors in a circular array
- 13-stage axial-flow compressor with advanced 3D design technology
- Variable inlet guide vanes
- Four-stage turbine
- Advanced cooling technology
- Low-NO<sub>x</sub> combustion system
- Cooled, filtered rotor cooling air

### Fuel Delivery System

The CTGs will be fueled by pipeline quality natural gas and ultra low sulfur distillate (ULSD) fuel oil. A supplier will furnish the natural gas by pipeline to the property boundary at a pressure sufficient for use in the CTGs without fuel compression. The natural gas, which is a mixture of hydrocarbons (e.g., methane, ethane, or propane), will contain 0.2 grains or less of total sulfur per 100 standard cubic feet and have a gross calorific value (higher heating value; HHV) of 1020 Btus per standard cubic foot. Tanker trucks will deliver the fuel oil and unload into above ground storage tanks. The ULSD fuel oil will contain a maximum of 0.0015% sulfur content by weight (15 ppm) and have a HHV of approximately 130,000 Btus per gallon.

The natural gas will undergo several steps to remove particulate matter and any liquid that may be carried through from the pipeline. First, the gas will be sent through a knockout drum for liquid removal. Next, it will pass through a double chamber filter/separator to take out particulate matter and entrained liquid. Six filter/separators will be included, one for each CTG. The first chamber removes particulates and liquids as the gas flows through a filtration section. Liquid that coalesces on filter cartridges drops to the bottom of the chamber, and then, either vaporizes and returns to the gas stream or drains to a sump. The second chamber eliminates any remaining entrained liquid in the gas stream by impingement on a net or labyrinth. Hydrocarbon liquids, which drain to the sump, will be collected for off-site disposal. Finally, the gas will be delivered to the CTGs and burned as part of the power generation operation.

The fuel oil will undergo less preparation. The fuel will be pumped from storage tanks, filtered (particulate removal only), and combusted in the CTGs.

#### Emergency Diesel Generator

One on-site emergency diesel-fired generator (ID No. ES7, 2000 hp, 14 million Btu per hour maximum heat input) will provide backup electricity for lube oil pumps, auxiliary cooling water pumps, water supply pumps and turning gears. The generator is not intended to provide sufficient power for a black start. It will operate less than 500 hours per year in emergency situations.

#### Fire-Water Pump Engine

One small diesel-fired engine (ID No. ES8, 208 hp, 1.5 million Btu per hour maximum heat input) will operate less than 500 hours per year as the fire-water pump driver.

#### Fuel Gas Heater

One natural gas-fired fuel gas heater (ID No. ES9; 4.0 million Btu per hour maximum heat input) will be used to warm up the incoming natural gas to prevent the freezing of the gas regulating valves under certain gas system operating conditions (i.e. high pressure).

#### Fuel Storage Tanks 1 and 2

Two above ground storage tanks will store the ULSD fuel oil for the combustion turbines. Tank 1 (ID No. ES10) will be 98 feet in diameter with a 2.2 million gallon storage capacity while Tank 2 (ID No. ES11) will be 69 feet in diameter with a 1.1 million gallon storage capacity. Both tanks will be 40 feet in height and have dome roofs. The maximum true vapor pressure of the tank contents will be 0.0077 psia (0.053 kPa).

## **2.2 Emissions**

CCGF emissions include PM, PM<sub>10</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO, and VOC. Potential emissions will occur primarily from the natural gas/fuel oil-fired CTGs and to a much lesser extent, from the emergency generator, fire water pump, fuel gas heater, and fuel storage tanks. Southern Power is proposing to restrict CTG fuel oil operations to 114,966 million Btu per day (54 turbine hours per day total and an average of 9 turbine hours per day each), CTG operations for all fuels to 26,520,000 million Btu per year (12,000 full load equivalent turbine hours per calendar year), and fire pump and diesel generator operations to 500 hours per year each to reduce potential

emissions. To further limit emissions, once fuel oil operations exceed 89,418 million Btu in a calendar day, no natural gas operations will be allowed for the remainder of that day. Southern Power requested this restriction on natural gas operation in order for the facility to demonstrate insignificant impacts for PM10 (24-hour averaging period) via the air dispersion modeling analysis. The fuel gas heater may operate continuously.

To evaluate the worst-case hourly emissions for the CTGs, as restricted, the applicant calculated emissions for each fuel under four operating loads at three ambient temperatures (100°F, 65°F, and 0°F). The operating loads for the CTGs when firing natural gas include 100% with evaporative cooler, 100% without evaporative cooler, 80%, and 60% and when firing fuel oil consist of 100% with evaporative cooler, 100% without evaporative cooler, 80%, and 70%. Maximum criteria pollutant emissions from CCGF are listed in the table below:

**Table 2-1 Potential Emission Rates for CCGF**

Compounds	PSD Significant Emission Rates Tons Per Year	Net Emissions Increase/Decrease Tons Per Year	PSD Review Required?
NO <sub>x</sub>	40	1,319.23	<b>Yes</b>
CO	100	450.00	<b>Yes</b>
PM	25	234.81	<b>Yes</b>
PM <sub>10</sub>	15	234.81	<b>Yes</b>
SO <sub>2</sub>	40	14.40	No
VOC (ozone precursor)	40	62.01	<b>Yes</b>
Lead	0.6	0.0814	No
Sulfuric Acid Mist	7	2.07	No

Potential PM, PM<sub>10</sub>, NO<sub>x</sub>, CO, and VOC emissions will exceed their respective PSD significance thresholds, and hence, PSD review is required for these pollutants. For all other remaining pollutants, SO<sub>2</sub>, lead, and sulfuric acid mist, the emissions due to the project will be less than their respective PSD significance thresholds, and thus PSD review is not required for these pollutants.

## SECTION 3.0

### REGIONAL DESCRIPTION

#### 3.1 Area Classification

The facility will be located in Cleveland County, North Carolina near the intersection of I-85 and the South Carolina border on a 283 acre tract. The facility coordinates are 35° 10' 14" (latitude) and 81° 24' 58" (longitude). Broad, gently rolling plateaus, which lie within the Broad River drainage basin, characterize the southern Cleveland County landscape. The surrounding site (3-km region) is of primarily agricultural use with surrounding swamplands.

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

<b>Pollutant</b>	<b>Attainment Status</b>
TSP	Attainment
PM <sub>10</sub>	Unclassified/Attainment
PM <sub>2.5</sub>	Unclassified/Attainment
Sulfur Dioxide	Unclassified/Attainment
Nitrogen Dioxide	Attainment
Carbon Monoxide	Unclassified/Attainment
Ozone	Unclassified/Attainment
Lead	Attainment

Cleveland County is considered a Class II Area.

The closest Class I Area from this facility is northwest of the facility. Class I Area Shining Rock Wilderness and Class I Area Great Smoky Mountain National Park are also located 130 km and 165 km, respectively, west of the proposed site.

## SECTION 4.0

### REGULATORY ANALYSIS

The following discussion pertains to the regulatory requirements that must be met for the construction and operation of the Cleveland County Generating Facility. These requirements include both federal Prevention of Significant Deterioration (PSD) regulations and State air quality regulations.

#### **4.1 PSD Applicability and Required Analysis**

The goal of the PSD regulations is to ensure that the air quality in clean (i.e. attainment) areas does not deteriorate significantly while maintaining a margin for future industrial growth. The PSD regulations focus on industrial facilities, both new and modified, that create significant increases in the emission of certain pollutants. The U.S. EPA promulgated final regulations governing the PSD permitting program in the Federal Register published August 7, 1980. Effective March 25, 1982, the DAQ received full authority from the EPA to implement PSD regulations in the State. Revisions to the PSD Regulations were subsequently promulgated on December 31, 2002 and adopted by the DAQ on July 28, 2006.

Under PSD requirements, all major new or modified stationary sources of air pollutants regulated as defined in Section 169 of the Clean Air Act (CAA) must be reviewed and approved prior to construction by U.S. EPA or the permitting authority, as applicable, in accordance with Section 165 of the CAA. A "major stationary source" is defined as any one of 28 named source categories with the potential to emit 100 tons per year or more of any regulated pollutant, or any other stationary source that has the potential to emit 250 tons per year or more of any PSD regulated pollutant. CCGF is not one of the 28 listed source categories. Hence, the major source threshold is 250 tpy of any regulated pollutant. As proposed, CCGF will have the potential to emit greater than 250 tpy each of nitrogen oxides (NO<sub>x</sub>) and carbon monoxide (CO). Therefore, CCGF is considered a PSD major stationary source as defined by 40 CFR 51.166 (b)(1)(i)(b). Under PSD, a source that is major for NO<sub>x</sub> is also considered major for ozone.

As a major stationary source, Southern Power is required to meet certain review requirements for each pollutant resulting from the proposed Cleveland County electrical generating facility, which may be emitted greater than the PSD significance level. PM, PM<sub>10</sub>, NO<sub>x</sub>, CO, and VOC are all potentially emitted from the proposed facility above their respective PSD significance level and therefore, are subject to PSD review. As required, Southern Power performed the following reviews and analyses for each new emission unit contributing to the potential emission increase of any regulated air pollutant equal to or exceeding its significance threshold, pursuant to 40 CFR 51.166(j) though (q) implemented through 15A NCAC 2D .0530.

- 1) A Best Available Control Technology (BACT) determination,
- 2) Source impact analysis
- 3) Air quality impact analysis

- 4) Additional Impacts Analysis including effects on soils, vegetation, and local visibility
- 5) Class I increment analysis

Under PSD regulations, the determination of the necessary emission control equipment is developed through a BACT review. 40 CFR 51.115(b)(12) defines BACT 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 energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.*

In the October 1980 final guidance document entitled “Prevention of Significant Deterioration – Workshop Manual,” EPA states “A BACT determination is dependent on the specific nature of the factors for that particular case. The depth of a BACT analysis should be based on the quantity and type of pollutants emitted and the degree of expected air quality issues.” The following passages from the legislative history of the Clean Air Act provide valuable insight for state agencies when making BACT decisions.

*“The decision regarding the actual implementation of best available technology is a key one, and the **committee places this responsibility with the State**, to be determined on a case-by-case judgment. It is recognized that the phrase has broad flexibility in how it should and can be interpreted, depending on site.*

*In making this key decision on the technology to be used, the State is to take into account energy, environmental, and economic impacts and other costs of the application of best available control technology. **The weight to be assigned to such factors is to be determined by the State.** Such a flexible approach allows the adoption of improvements in technology to become widespread far more rapidly than would occur with a uniform Federal standard. The only Federal guidelines are the EPA new source performance and hazardous emissions standards, which represent a floor for the State’s decision.*

*This directive enables the State to consider the size of the plant, the increment of air quality, which will be absorbed by any particular major emitting facility, and such other considerations as anticipated and desired economic growth for the area. This allows the States and local communities to judge how much of the defined increment of significant deterioration will be devoted to any major emitting facility. If, under the design which a major facility proposes, the percentage of increment would effectively prevent growth after the proposed major facility was completed, the State or local community could refuse to permit construction, or limit its size. **This is strictly a State and local decision; this legislation provides the parameters for that decision.***

*One of the cornerstones of a policy to keep clean areas clean is to require that new sources use the best available technology available to clean up pollution. One objection which has been raised to requiring the use of the best available pollution control technology is that a technology demonstrated to be applicable in one area of the country is not applicable at a new facility in another area because of the differences in feedstock material, plant configuration, or other reasons. **For this and other reasons the Committee voted to permit emission limits based on the best available technology on a case-by-case judgment at the State level. [emphasis added].** This flexibility should allow for such differences to be accommodated and still maximize the use of improved technology.”*

The BACT requirements are intended to ensure that the control systems incorporated in the design of the proposed project 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 may consider the impacts of non-criteria pollutants and unregulated toxic air pollutants, if any are emitted, when making the BACT decision for regulated pollutants. Under the BACT requirement 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 can be found in Section 5 of this document.

#### **4.2 NCDAQ Air Pollution Regulations**

In addition to the PSD requirements, the NCDAQ has promulgated air pollution control and permitting requirements under Title 15A NCAC Sub-Chapters 2D and 2Q. Under the BACT requirements of PSD regulations, all BACT emission limits must, at a minimum, comply with any applicable standard of performance under 40 CFR Parts 60 (New Source Performance Standards) and Parts 61 and 63 (National Emission Standards for Hazardous Air Pollutants), and the North Carolina State Implementation (SIP) plan. The NCDAQ emission control regulations that affect the proposed facility are summarized in Table 4.1.

**Table 4-1 Regulatory Requirements**

REGULATION	EMISSION SOURCES	POLLUTANTS	REGULATORY REQUIREMENTS
2Q .0101	All emission sources	NA	Obtain permit for all sources of air emissions not specifically exempted.
2D .0516	Simple Cycle Dual Fuel Combustion Turbines (ID Nos. ES1, ES2, ES3, ES4, ES5 and ES6), Diesel Emergency Generator (ID No. ES7), Emergency Fire Water Pump (ID No. ES8), and Natural Gas-Fired Heater (ID Nos. ES9)	SO <sub>2</sub>	Limit emissions to 2.3 pounds per million Btu.
2D .0521	All emission sources	Visible emissions	Limit opacity to 20 percent.
2D .0524 <b>NSPS Kb</b>	Fuel Oil Storage Tanks 1 and 2 (ID Nos. ES10 and ES11)	VOC	Tanks are <b>EXEMPT</b> since the maximum vapor pressure of the fuel stored is less than 3.5 kPa.
2D .0524 <b>NSPS IIII</b>	Diesel Emergency Generator (ID No. ES7), and Emergency Fire Water Pump (ID No. ES8)	NO <sub>x</sub> , CO, PM, non-methane hydrocarbons, SO <sub>2</sub>	Maintain equipment supplier certification of compliance with emission standards.
			Through 9/30/2010, limit sulfur content may to 500 ppm. Beginning 10/1/2010, limit sulfur content in fuel to 15 ppm.
2D .0524 <b>NSPS KKKK</b>	Simple Cycle Dual Fuel Combustion Turbines (ID Nos. ES1, ES2, ES3, ES4, ES5 and ES6)	SO <sub>2</sub>	Limit SO <sub>2</sub> emissions to 0.90 lb/megawatt-hour while firing natural gas or No. 2 fuel oil <b>OR</b> Burn only fuels with potential emissions not exceeding 0.60 lb/megawatt-hour.
		NO <sub>x</sub>	Limit NO <sub>x</sub> emissions to 0.0015% by volume at 15% O <sub>2</sub> and on a dry basis (15 ppmvd at 15% O <sub>2</sub> ), while firing natural gas.
			Limit NO <sub>x</sub> emissions to 0.0042% by volume at 15% O <sub>2</sub> and on a dry basis (42 ppmvd at 15% O <sub>2</sub> ), while firing fuel oil.
2D .0530	Simple Cycle Dual Fuel Combustion Turbines (ID Nos. ES1, ES2, ES3, ES4, ES5 and ES6), Diesel Emergency Generator (ID No. ES7), Emergency Fire Water Pump (ID No. ES8), and Natural Gas-Fired Heater (ID Nos. ES9)	NO <sub>x</sub> , CO, VOC, and PM/ PM <sub>10</sub> ,	Undergo PSD review for new sources.

REGULATION	EMISSION SOURCES	POLLUTANTS	REGULATORY REQUIREMENTS
2D .0530 (h)	Simple Cycle Dual Fuel Combustion Turbines (ID Nos. ES1, ES2, ES3, ES4, ES5 and ES6)	SO <sub>2</sub>	Install BACT for new combustion turbines.
2D .0535	All emission sources	All regulated pollutants	Notify the Director within 24 hours of emissions in excess of established permit limits that last for more than 4 hours.
2D .0614	Simple Cycle Dual Fuel Combustion Turbines (ID Nos. ES1, ES2, ES3, ES4, ES5 and ES6)	NO <sub>x</sub>	Does <b>NOT</b> apply since turbines are subject to NSPS, Subpart KKKK.
2D .1111	Simple Cycle Dual Fuel Combustion Turbines (ID Nos. ES1, ES2, ES3, ES4, ES5 and ES6)	HAP	Does <b>NOT</b> apply since site HAP emissions are less than 10/25 tpy.
2D .1111 <b>MACT ZZZZ</b>	Diesel Emergency Generator (ID No. ES7), and Emergency Fire Water Pump (ID No. ES8)	HAP	Comply with the applicable requirements of 40 CFR 60 Subpart IIII.
2Q .0402	Simple Cycle Dual Fuel Combustion Turbines (ID Nos. ES1, ES2, ES3, ES4, ES5 and ES6)	NO <sub>x</sub>	Permittee is required to submit Acid Rain application by the deadline in future, as per the applicable requirement.
2D .1418	Simple Cycle Dual Fuel Combustion Turbines (ID Nos. ES1, ES2, ES3, ES4, ES5 and ES6)	NO <sub>x</sub>	Limit NO <sub>x</sub> emissions to 0.15 lb/million Btu for gaseous fuel and 0.18 lb/million Btu for liquid fuels, OR Limit NO <sub>x</sub> emissions to BACT limits established under 2D .0530.

#### 4.2.1 15A NCAC 2Q .0101 (All Emission Sources)

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. 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".

#### 4.2.2 15A NCAC 2D .0516 “Sulfur Dioxide Emissions from Combustion Sources” (Combustion turbines, emergency generator, fire pump, and heater)

Sulfur dioxide emissions from combustion sources may not exceed 2.3 pounds per million Btu heat input. Due to the inherently low sulfur concentrations in ULS fuel oil and natural gas, compliance with this standard is expected.

#### **4.2.3 15A NCAC 2D .0521 “Control of Visible Emissions” (All Emission Sources)**

The intent of this Rule is to prevent, abate and control emissions generated from fuel burning operations and industrial processes where an emission 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. 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, emergency generator, fire-water pump, heater, and tanks are subject to this standard. Visible emissions due to burning of natural gas and ULS distillate fuel are expected to be negligible due to inherently clean fuel. Compliance is expected.

#### **4.2.4 15A NCAC 2D .0524 - New Source Performance Standards (NSPS)**

##### **Subpart Kb –Standards of Performance for Volatile Organic Liquid Storage Vessels**

This subpart applies to storage vessels with a capacity greater than or equal to 151 m<sup>3</sup> storing a liquid with a maximum true vapor pressure more than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m<sup>3</sup> but less than 151 m<sup>3</sup> storing a liquid with a maximum true vapor pressure more than 15.0 kPa. Although the proposed storage tanks have capacities greater than 151 m<sup>3</sup>, the vapor pressure of the distillate fuel, at its maximum storage temperature of 67.37 °F, is only 0.053 kPa. Therefore, Subpart Kb does NOT apply.

##### **Subpart IIII- Standards of Performance for Stationary Compression Ignition Internal Combustion Engines**

The proposed emergency generator and fire-water pump engine are 2007 model year or later stationary, diesel-fired, internal combustion (IC) engines subject to 40 CFR 60 Subpart IIII. For these engines, Southern Power is required to demonstrate compliance by purchasing engines certified by the manufacturer to meet the NO<sub>x</sub>, CO, PM, and non-methane hydrocarbon (NMHC) emission standards and by using low sulfur fuel with a minimum cetane number and a maximum aromatic content. Compliance is expected.

## **Subpart KKKK- Standards of Performance for Stationary Combustion Turbines**

40 CFR 60 Subpart KKKK regulates stationary combustion turbines with peak loads 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. The new combustion turbines each have peak load heat input rates substantially greater than 10 million Btu per hour and are, therefore, subject to NSPS. Subpart KKKK requires the Permittee to operate and maintain the proposed combustion turbines, dry low NO<sub>x</sub> burners, SCRs, and any monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during start-up, shutdown, and malfunction. Furthermore, it establishes emission limits for NO<sub>x</sub> and SO<sub>2</sub>.

Under Subpart KKKK, the proposed turbines are subject to a NO<sub>x</sub> emission standard of 15 ppm at 15% O<sub>2</sub> or 0.43 lb/MWh, when firing natural gas and 42 ppm at 15% O<sub>2</sub> or 1.3 lb/MWh while firing fuel oil. Unrestricted emissions are expected to exceed the emission standards. With the use of DLN burners when natural gas is fired, and water injection when distillate fuel is fired, Southern Power expects to maintain emissions at or below the allowed concentration limits. Maximum NO<sub>x</sub> emissions allowed by BACT are 9 ppmvd at 15% O<sub>2</sub> (natural gas) and 42 ppmvd at 15% O<sub>2</sub> (distillate fuel). Therefore, compliance with BACT ensures compliance with Subpart KKKK.

The proposed turbines are also subject to an emission limit of 0.90 lb SO<sub>2</sub>/MWh gross output or a sulfur fuel content limit of 0.06 lb SO<sub>2</sub>/million Btu heat input. The turbines will burn only pipeline quality natural gas or ULS distillate fuel. Southern Power expects the natural gas to contain no more than 0.2 grains of sulfur per ft<sup>3</sup> and have a heating value of 1,020 Btus/ft<sup>3</sup> and the ULS distillate fuel to contain no more than 0.0015% sulfur by weight and have a net heating value of 18,450 Btu/lb. The calculated SO<sub>2</sub> emission rates when natural gas and distillate fuel are fired in the turbines are 0.00056 lb/million Btu and 0.0545 lb/million Btu, respectively. Therefore, compliance is expected.

Subpart KKK has monitoring requirements for when water/steam injection **is** and **is not** used to control NO<sub>x</sub> emissions. Southern Power plans to use water injection to reduce NO<sub>x</sub> emissions when distillate fuel is fired in the turbines. To comply with Subpart KKKK, the Permittee must install, calibrate, maintain and operate a continuous monitoring system to monitor and record either the fuel consumption and the ratio of water or steam to fuel being fired in the turbine or the hourly NO<sub>x</sub> emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu). For turbines complying with the output-based standard, the Permittee must also install, calibrate, maintain, and operate a fuel flow meter(s) to continuously measure the heat input to the affected unit; a watt meter(s) to continuously measure the gross electrical output of the unit in megawatt-hours; and meter(s) to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

Southern Power plans to use DLN burners instead of water injection to reduce NO<sub>x</sub> emissions when natural gas is fired in the turbines. To comply with Subpart KKKK, the Permittee must conduct annual performance tests (subsequent to initial performance test) to demonstrate

compliance. If the performance test indicates NO<sub>x</sub> emissions are less than or equal to 75 percent of the emission limit, the testing frequency 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<sub>x</sub> emission limit, the Permittee must resume the annual performance tests. As an alternative to testing, the Permittee may install, calibrate, maintain and operate a continuous monitoring system to monitor:

- (1) The hourly NO<sub>x</sub> emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu). For turbines complying with the output-based standard, the Permittee must also install, calibrate, maintain, and operate a fuel flow meter(s) to continuously measure the heat input to the affected unit; a watt meter(s) to continuously measure the gross electrical output of the unit in megawatt-hours; and meter(s) to continuously measure the total thermal energy output in British thermal units per hour (Btu/h). OR
- (2) Continuous parameter monitoring as follows:
  - (i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO<sub>x</sub> formation characteristics, and you must monitor these parameters continuously.
  - (ii) For any lean pre-mix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO<sub>x</sub> mode.
  - (iii) For any turbine that uses SCR to reduce NO<sub>x</sub> emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls. OR
- (3) With the DAQ approval for the affected units which are also subject to Part 75, monitor the NO<sub>x</sub> emission rate using the Part 75 Appendix E methodology or the low mass emissions methodology in §75.19.

Southern Power will likely install NO<sub>x</sub> CEMS; however they have requested the permit allow all of the compliance demonstration options available under the regulations.

The Permittee must also demonstrate that potential sulfur emissions do not exceed 0.06 lb SO<sub>2</sub>/million Btu heat input. The Permittee may use a valid purchase contract, tariff sheets or a transportation contract to show the total sulfur content for natural gas is 20 grains of sulfur or less per 100 ft<sup>3</sup> and the total sulfur content for the fuel oil is 0.05% by weight or less or may use representative sampling data to show that the sulfur content of both fuels does not exceed 0.06 lb SO<sub>2</sub>/million Btu heat input. Compliance is expected as the CCGF's fuel specifications limit sulfur to a maximum of 20 grains per 100 ft<sup>3</sup> of natural gas and 0.0015% by weight for the fuel oil.

The Permittee is required to conduct initial and subsequent performance tests as per §60.4400 and §60.4415 for NO<sub>x</sub> and SO<sub>2</sub>, respectively, within 180 days of the initial start-up of the

combustion turbines. 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 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 a high compliance margin with the NO<sub>x</sub> emission standard. Refer to EPA ADI Control Numbers 0300035, 0100007, and 0300053. Thus, DAQ will require initial performance testing for only one of six combustion turbines. Each performance test 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.

The Permittee can opt to monitor the total sulfur content of the fuel being fired in the turbine in lieu of the stack testing to demonstrate compliance with SO<sub>2</sub> stack limit. For this option, the total sulfur methods in §60.4415 must be followed. Natural gas monitoring is required once per unit operating day since the fuel is supplied without intermediate bulk storage. For fuel oil, the Permittee must use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

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 turbine operation, including start-up, shutdown, and malfunction. The Permittee must also submit the results of any performance test within 60 days of completion.

#### **4.2.5 15A NCAC 2D .0530 - Prevention of Significant Deterioration**

New major stationary sources of air pollutants regulated as defined in Section 169 of the Clean Air Act (CAA) are subject to all the requirements as defined in 40 CFR 51.166. These requirements include:

- A demonstration that the BACT is applied to each emission unit that will emit any PSD regulated pollutant above the significant threshold, including a demonstration that emissions of air toxics will not exceed the acceptable ambient levels (AAL's) as regulated by the NCDAQ.
- A demonstration that neither allowable PSD ambient air increments nor NAAQS will be exceeded 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 local 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 exceed the Class I increment.

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

#### **4.2.6 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, resulting from a malfunction that last for greater than four hours. This report must be made within 24 hours of becoming aware of the occurrence.

#### **4.2.7 NCAC 2D .1111 - Maximum Achievable Control Technology**

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 of HAPs. The maximum individual and total HAP emissions from the proposed CCGF are less than 3 tpy and 7 tpy, respectively. Therefore, Subpart YYYY does not apply.

EPA has promulgated MACT Subpart ZZZZ for emissions of hazardous air pollutants (HAP) from stationary reciprocating internal combustion engines (RICE). The MACT applies to RICE sited at major sources of HAPs as well as RICE, whose construction commenced on or after June 12, 2006, located at an area source (i.e. site with the potential to emit less than 10 tpy of a single HAP and less than 25 tpy of a combination of HAPs). Since construction of the emergency generator and firewater pump engine (ID Nos. ES7 and ES8) will begin after 2006, the RICE MACT applies. In accordance with §63.6590(c), the Permittee must meet the requirements of 40 CFR 63 Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII, for compression ignition engines. No further requirements apply for such engines under this MACT.

#### **4.2.8 15A NCAC 2D .1418 - New Electric Generating Units, Large Boilers, and Large I/C Engines**

This regulation is NC's NO<sub>x</sub> 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 any amount of electricity. The proposed project includes the installation of six dual fueled simple-cycle CTGs, each with a nominal electrical generating capacity of 190 MW, which are expected to be permitted in 2008 or after. Hence, they are subject to the regulation.

NO<sub>x</sub> emissions from these combustion turbines cannot exceed 0.15 lb/million Btu when firing natural gas and 0.18 lb/million Btu when firing fuel oil or, if more restrictive, the BACT limits under 15A NCAC 2D .0530. Proposed BACT limits are more restrictive for natural gas and equivalent for fuel oil. Therefore, compliance with the proposed BACT limits ensures compliance with 2D .1418.

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<sub>x</sub> allocations for the turbines as per the procedures established in 2D .1421.

#### **4.2.9 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" as per 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 SO<sub>2</sub> allowances and track the allocated emissions using CEMs. The Permittee will also be required to accurately report NO<sub>x</sub> emissions on an annual basis using CEMs.

## SECTION 5.0

### BEST AVAILABLE CONTROL TECHNOLOGY

#### 5.1 BACT

Each pollutant subject to a PSD review must meet the criteria of BACT, which refers to the maximum amount of emission reduction currently possible with respect to technical application and economic, energy, and environmental considerations. 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 Part 60 and 61.

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 BACT for the emission source.

As indicated in Section 4.1 above, the change in emissions due to the project for NO<sub>x</sub>, CO, PM, PM<sub>10</sub>, and VOC will exceed their respective significance thresholds. The BACT analysis will

focus on applicable control techniques for simple cycle combustion turbines, natural gas heaters, and emergency diesel engines for the above pollutants.

## 5.2 Previous BACT Determinations

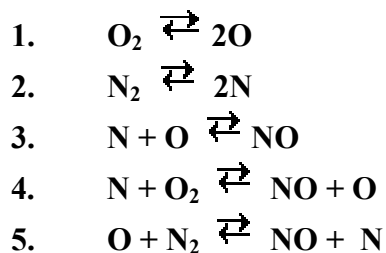
NCDAQ searched the RACT/BACT/LAER (RBL) Clearinghouse for the time period from January 1, 2003 to present, to identify and evaluate the current BACT determinations for NO<sub>x</sub>, PM/PM<sub>10</sub>, CO, and VOC emissions from simple cycle combustion turbines, natural gas-fired heaters, and diesel emergency engines. A brief summary of findings of this search is included in Appendix C.

## 5.3 BACT Analysis for NO<sub>x</sub>

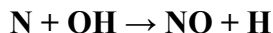
NO<sub>x</sub> emissions have adverse health effects and play a role in ground level ozone formation, acid rain deposition, global warming (potentially), water quality degradation, reduced visibility, and the formation of toxic air pollutants. The most abundant forms of NO<sub>x</sub> emissions from combustion sources are nitric oxide (NO) and nitrogen dioxide (NO<sub>2</sub>). Nitric oxide is an odorless, colorless, toxic gas. NO<sub>2</sub> is also a toxic gas, but unlike NO, it is highly corrosive with a pungent odor and a reddish-brown appearance. Over time, in the presence of oxygen, most NO is converted to NO<sub>2</sub>. The reddish brown NO<sub>2</sub> gas blocks the transmission of light, reduces visibility, and creates haze. NO<sub>x</sub> emissions also increase nitrogen loading in coastal estuaries and upset the chemical balance of nutrients used by aquatic plants and animals. Elevated nitrogen levels promote excessive plant growth, which eventually leads to oxygen depletion and reductions in fish and shellfish populations

During combustion, NO<sub>x</sub> is formed through the high temperature oxidation of the diatomic nitrogen found in combustion air (thermal NO<sub>x</sub>) and through the release of the nitrogen bound in the fuel, which ultimately reacts to forms NO<sub>x</sub> (fuel NO<sub>x</sub>). Almost all of the NO<sub>x</sub> from natural gas combustion is thermal NO<sub>x</sub>, while up to half of the NO<sub>x</sub> from fuel oil combustion is fuel NO<sub>x</sub>. Thermal NO<sub>x</sub> formation is a function of the combustion temperature and the residence time of nitrogen at that temperature. NO<sub>x</sub> production increases exponentially with increases in combustion temperature. (Note, fuel oil combustion occurs at higher temperatures than natural gas combustion, thus, resulting in higher NO<sub>x</sub> emissions.) At high temperatures, usually above 1600°C (2900°F), nitrogen (N<sub>2</sub>) and oxygen (O<sub>2</sub>) in the combustion air disassociate and participate in a series of reactions, known as the Zeldovich Mechanism.

### Zeldovich Mechanism Reactions



NO<sub>x</sub> is also formed by the reaction of nitrogen (N<sup>+</sup>) with hydroxide (OH<sup>-</sup>)



The flame temperature is a function of the stoichiometric ratio of the fuel to oxygen. The highest flame temperature occurs when this ratio is 1, where the flame temperature is equal to the adiabatic flame temperature. NO<sub>x</sub> formation decreases rapidly for either fuel rich (ratio > 1.0) or fuel lean combustion (ratio < 1.0).

### NO<sub>x</sub> Control Alternatives

NO<sub>x</sub> control can be achieved in the combustion process or through add on controls which remove NO<sub>x</sub> from the flue gas. Combustion control involves minimizing the peak combustion temperature, reducing residence time, and/or maintaining fuel lean or fuel rich combustion. Post-combustion control entails using a reducing agent to convert NO<sub>x</sub> to nitrogen gas and water. The Encyclopedia of Environmental Science and Engineering list the following methods for NO<sub>x</sub> control:<sup>1</sup>

**Table 5.3-1 NO<sub>x</sub> Control Technology**

<b>CONTROL TECHNOLOGY</b>	<b>NO<sub>x</sub> REDUCTION</b>
Low excess air	1 – 15%
Selective non-catalytic reduction (SNCR) - Urea	25 – 50%
SNCR - Ammonia	25 – 50%
Off stoichiometric combustion	30 – 60%
Water/steam injection	40 – 70%
Flue gas recirculation (FGR)	40 – 80%
<u>Low NO<sub>x</sub> Burner</u>	
• Low excess air burner	20 – 25%
• Staged-air burner	25 – 35%
• Staged-fuel burner	40 – 50%
• Burner with internal FGR	40 – 50%
• Burner with external FGR	50 – 60%
• Air or fuel staging with internal FGR	55 – 75%
• Air or fuel staging with external FGR	60 – 80%
Selective catalytic reduction (SCR)	70 – 90%

Techniques used to reduce NO<sub>x</sub> emissions from natural gas-fired simple cycle combustion turbines include dry-low NO<sub>x</sub> combustors (DLN) and selective catalytic reduction (SCR). For fuel oil-fired simple cycle CTG's, water injection is typically used to minimize NO<sub>x</sub> formation. Note flue gas recirculation (FGR) is not technically viable for simple cycle CTGs. Good combustion practices and low NO<sub>x</sub> burners are effective at limiting the NO<sub>x</sub> generated from

<sup>1</sup> *Encyclopedia of Environmental Science and Engineering*, Fifth Edition, Volumes One and Two: James R. Pfafflin, Edward N. Ziegler, January 2006

natural gas-fired heaters. Control techniques for reducing NO<sub>x</sub> emissions from diesel engines include injection timing retardation and good combustion practices.

**Table 5.3-2 NO<sub>x</sub> Control Technology Feasibility Evaluation**

<b>CONTROL TECHNOLOGY</b>	<b>TECHICAL FEASABILITY DISCUSSION</b>	<b>CONSIDERED FURTHER?</b>
Dry Low-NO <sub>x</sub> (DLN) Combustion	Dry Low NO <sub>x</sub> combustion reduces NO <sub>x</sub> formation through enhanced mixing of combustion fuel and air. DLN combustors are designed to control the peak temperature, residence time, and the availability of free oxygen in the combustion zone. They minimize thermal NO <sub>x</sub> formation by reducing the combustion temperatures and the available excess oxygen levels. DLN 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 pre-mixture of fuel and air are burned in order to assure a uniform mixture and the avoidance of high temperature regions in the combustor. DLN technology has been used to reduce NO <sub>x</sub> emissions for more than 15 years and is considered BACT for most natural gas fired simple cycle CTGs. This control technology is technically feasible for natural gas fired combustion turbines and is evaluated further.	YES
Water or Steam Injection	Water or steam injection involves injecting water or steam into the high temperature region of the flame to reduce the peak flame temperature. This control technique keeps much of the available oxygen from getting ionized. The degree of NO <sub>x</sub> formation reduction is proportional to the amount of water injected in the turbine. The technology is considered technically feasible and is evaluated further.	YES
Injection Timing Retardation	Injection timing retardation (ITR) reduces the peak flame temperature by delaying the heat release in the cycle. At lower flame temperatures, less NO <sub>x</sub> is formed. This technology is considered technically feasible and is evaluated further.	YES
Good Combustion Control	Good combustion practices minimize NO <sub>x</sub> by controlling the distribution of air at the air and fuel injection zones to maintain fuel lean combustion and thereby, operate at lower peak flame temperatures.	YES

CONTROL TECHNOLOGY	TECHICAL FEASABILITY DISCUSSION	CONSIDERED FURTHER?
Selective Catalytic Reduction (SCR)	<p>Selective catalytic reduction (SCR) is a post-combustion control technique which uses a reducing agent, with the aid of a catalyst, to convert NO<sub>x</sub> into N<sub>2</sub> and water. The use of the catalyst lowers the activation energy and allows the reduction to proceed at temperatures between 480 and 800 °F. Most commercial SCR systems utilize base metal catalysts (vanadium or titanium) and operate over a temperature range of approximately 500-750 °F. A given catalyst achieves 70 to 90% NO<sub>x</sub> reduction within a 100-200 °F temperature range. At temperatures outside this window, the catalyst becomes ineffective and NO<sub>x</sub> reduction decreases. Excess temperatures can permanently damage the catalyst. Ammonia slip, the release of unreacted ammonia, can occur when the catalyst bed temperature drops too low and when too much ammonia is injected. The reducing agent, typically anhydrous ammonia, aqueous ammonia, or urea, poses both environmental and safety risks. Pure anhydrous ammonia is extremely toxic and difficult to safely store and transport. Aqueous ammonia must be hydrolized and urea must undergo thermal decomposition to ammonia in order to be used as effective reductants. Ammonia slip, the release of unreacted ammonia, occurs when catalyst bed is not maintained within the optimum reaction range or when too much ammonia is injected. SCR is technically feasible for controlling NO<sub>x</sub> emissions from simple cycle combustion turbines but has very limited application for large (F-Class) frame turbines. A large-scale simple turbine in California will be one of the first to use SCR for controlling NO<sub>x</sub> from a large-scale simple turbine. This technology is evaluated further.</p>	YES
Selective Non-Catalytic Reduction (SNCR)	<p>Selective non-catalytic reduction (SNCR) is a post-combustion control technique that involves injecting either ammonia or urea into flue gas that is optimally between 1600 °F and 1900 °F. In this temperature range, ammonia effectively reduces 25 to 50% of the NO<sub>x</sub> to elemental nitrogen N<sub>2</sub> and water. At lower temperatures, the reduction reaction does not proceed and at higher temperatures, the nitrogen in the ammonia forms additional NO<sub>x</sub>. Because the exhaust temperature at the exit of the combustion turbines proposed for this project is considerably less than the optimum temperature range for the application of this technology, the use of SNCR is <b>not</b> technically feasible.</p>	NO

CONTROL TECHNOLOGY	TECHICAL FEASABILITY DISCUSSION	CONSIDERED FURTHER?
SCONO <sub>x</sub>	<p>Goal Line Environmental Technologies in conjunction with ABB Alstom Power has developed a post-combustion control technology known as SCONO<sub>x</sub>, which utilizes a platinum-based catalyst coated with potassium carbonate (K<sub>2</sub>CO<sub>3</sub>) to oxidize NO<sub>x</sub> and CO to potassium nitrates and CO<sub>2</sub>, respectively. A hydrogen gas stream is periodically passed over the bed where it reacts with the potassium nitrates to form K<sub>2</sub>CO<sub>3</sub>, N<sub>2</sub> and water. SCONO<sub>x</sub> is reportably capable of achieving 90% NO<sub>x</sub> reductions for combustion turbine applications and is currently operating as BACT for several small natural gas-fired CTGs (under 40 MW). However, at this time, SCONO<sub>x</sub> is not commercially available for the large combustion turbines including the Siemens SGT6-5000F turbines and is not proven technology for fuel oil combustion. The SCONO<sub>x</sub> catalyst is very susceptible to fouling by sulfur in the flue gas. Furthermore, it is not suitable for the exhaust temperatures of simple cycle gas turbine peaking applications. This technology is <b>not</b> technically feasible.</p>	NO

The technically feasible control technologies for the proposed Siemens SGT6-5000F natural gas/distillate fuel oil-fired combustion turbines offering the greatest NO<sub>x</sub> reduction include SCR, DLN combustors, and water injection. The applicant further evaluated the practicality of applying these controls to the proposed CTGs.

### SELECTIVE CATALYTIC REDUCTION

The highest NO<sub>x</sub> reduction is achieved with SCR. With SCR, combustion turbine flue gas NO<sub>x</sub> levels are reduced to 5 ppm or less at 15% O<sub>2</sub>. Therefore, the economic, environmental, and energy impacts of SCR are further evaluated.

#### Economic Impact

The Permittee evaluated the cost impact of SCR to control NO<sub>x</sub> emissions from each of the combustion turbines for two operating conditions:

- A. 2,000 hours of operation per year with natural gas-fired
- B. 1,000 hours of operation per year with natural gas and 1,000 hours of operation per year with fuel oil

Southern Power projected that SCR would cost \$9,200 to \$19,400 per ton of NO<sub>x</sub> removed depending upon the type of fuel(s) used. This cost range is consistent with the BACT cost analysis for other simple cycle fuel oil-fired combustion turbines. Commonwealth Chesapeake Power Station in New Church, Virginia and Stock Island in Key West, Florida have estimated the cost of NO<sub>x</sub> removal with high temperature SCR at \$12,354 per ton (October 2000; simple cycle fuel oil-fired CTG) and \$13,410 per ton (October 2004 simple cycle ULS fuel oil-fired combustion turbine No. 4).

### Environmental Impact

The Clean Air Act requires the permitting authority to consider environmental impacts when making a BACT determination. See 42 U.S.C. §7479(3). The EPA issued guidance on BACT determinations including the appropriate use of the statutory BACT factors. This guidance is contained in a manual entitled “New Source Review Workshop Manual” (Draft, October 1990). On page B.49 EPA describes examples of environmental impacts that may be considered. They state,

*One environmental impact that could be examined is the trade-off between emissions of various pollutants resulting from the application of a specific control technology. The use of certain control technologies may lead to increases in emission of pollutants other than those the technology was designed to control. For example, the use of certain volatile organic compound (VOC) control technologies can increase nitrogen oxides (NO<sub>x</sub>) emissions. In this instance, the reviewing authority may want to give consideration to any relevant local air quality concern relative to a secondary pollutant (in this case NO<sub>x</sub>) in the region of the proposed source. For example, if the region in the example were nonattainment for NO<sub>x</sub>, a premium could be placed on the potential NO<sub>x</sub> increase. This could lead to the elimination of the most stringent VOC technology (assuming it generated high quantities of NO<sub>x</sub>) in favor of one having less of an impact on ambient NO<sub>x</sub> concentrations.*

The use of SCR has several environmental impacts. The spent catalyst is classified as a hazardous waste due to its vanadium content and, possibly, other trace metals and must be properly handled and disposed of following regulatory procedures. Within the SCR, the catalyst is expected to oxidize 2 to 3 percent of the SO<sub>2</sub> in the flue gas to SO<sub>3</sub>. This SO<sub>3</sub> may then react with moisture in the flue gas to form sulfuric acid mist or with unreacted ammonia in the flue gas to form two ammonium salts; ammonium bisulfate, which rapidly corrodes metal components, and ammonium sulfate. These salts increase the formation of fine particulates. Fine particulate emissions are a serious environmental concern as they adversely affect lung and heart function and are a major cause of decreased visibility (haze). When the turbines are fired by natural gas, these environmental impacts are minimum. They become significant when the turbines burn distillate fuel and increase in proportion to the sulfur content.

The use of ammonia as the reducing agent also poses environmental risk. Ammonia is listed as an acute irritant under the North Carolina Air Toxics Program, is considered a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA), and is regulated by USEPA’s Chemical Accident Prevention Provisions. In addition to forming fine particulates, ammonia has direct toxic effects on vegetation and contributes to atmospheric nitrogen deposition. When the SCR catalyst bed is initially charged, ammonia emissions will be low. However, as the catalyst bed degrades and approaches the design value for catalyst cleaning or replacement, ammonia slip increases. SCR catalyst degradation is expected to be a significant problem for the fuel oil-fired combustion turbines. A SCR control application for fuel oil-fired combined cycle combustion turbines at the PREPA Cambalache Plant in Puerto Rico experienced difficulty keeping ammonia slip below 10 ppmvd

for more than 1 to 2 months after catalyst cleaning. Numerous operational failures at the PREPA Cambalache Plant eventually led to EPA's decision in 2000 to approve the removal of the SCR system and to no longer consider the SCR as BACT.

### Energy Impact

The Clean Air Act requires the permitting authority to consider energy impacts when making a BACT determination. See 42 U.S.C. 7479(3), CAA Section 169(3). The EPA issued guidance on BACT determinations including the appropriate use of the statutory BACT factors. This guidance is contained in a manual entitled "New Source Review Workshop Manual" (Draft, October 1990). On page B.29 EPA describes the type of energy impacts that can be considered. They state,

*Applicants should examine the energy requirements of the control technology and determine whether the use of that technology results in any significant or unusual energy penalties or benefits. A source may, for example, benefit from the combustion of a concentrated gas stream rich in volatile organic compounds; or on the other hand, more often extra fuel or electricity is required to power a control device or incinerate a dilute gas stream.*

The use of SCR will reduce energy generation for the proposed turbines by increasing backpressure on the combustion turbines. Reducing NO<sub>x</sub> emissions to 5 ppmvd is expected to reduce the turbine output by 0.97 percent. The cost of additional fuel has been taken into consideration in the economic analysis.

### **DLN COMBUSTORS AND WATER INJECTION**

DLN combustors and water injection combustion control technologies are commercially available to control NO<sub>x</sub> emissions from the Siemens SGT6-5000F natural gas/distillate fuel oil-fired combustion turbines. These control methods represent a cost and energy effective NO<sub>x</sub> reduction approach. In DLN systems, fuel and air are premixed and then ignited in the combustion zone. The combustion reaction proceeds at a lower equivalence ratio (fuel lean) resulting in a lower flame temperature and decreased thermal NO<sub>x</sub> formation with little impact to cycle efficiency. DLN combustors can reduce NO<sub>x</sub> formation from natural gas-fired turbines to 9 ppm. However, DLN combustors are not viable options for fuel oil-fired combustion turbines. Fuel oil and air must be injected separately into the combustion chamber where they mix and combust. Injecting diluents, such as water, lowers the combustion temperatures and promotes mixing. Less NO<sub>x</sub> is formed at the lower flame temperature. As more water is injected, NO<sub>x</sub> formation and the thermal efficiency decreased and CO, which is a byproduct of incomplete combustion, and turbine wear increase. The lowest practical NO<sub>x</sub> levels achieved with injection are generally 25 ppm when firing natural gas and 42 ppm when firing fuel oil.

### **BACT for NO<sub>x</sub> Emissions from the Combustion Turbines**

BACT for the proposed combustion turbines operating in simple cycle mode is the use of DLN combustors while firing natural gas and the use of water injection while firing fuel oil. The proposed DLN combustion system will use ultra low NO<sub>x</sub> combustors to achieve NO<sub>x</sub> reduction. According to the applicant, "Ambient air is drawn into the 13 stage compressor of the SGT6-

5000F where it is compressed to a pressure ratio of approximately 17 atmospheres. The compressed air is then directed to the combustor section, which consists of 16 separate air-cooled, can-annular, Ultra Low NO<sub>x</sub> (ULN) combustors. Fuel is introduced, ignited and burned. The combustor outlet temperature is approximately 2,550 °F. The hot combustion gases routed through the air-cooled transition pieces are directed to the turbine (expansion) section. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically 65 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas is discharged at a temperature of approximately 1,100°F.” As designed, the vendor guarantees NO<sub>x</sub> emissions from natural gas combustion will not exceed 9 ppmvd @ 15% O<sub>2</sub> over the requested operating load range of 60% to 100% and NO<sub>x</sub> emissions from fuel oil combustion will not exceed 42 ppmvd @ 15% O<sub>2</sub> over the requested operating range of 70% to 100%. Therefore, based on consideration of energy, economics, and environmental impacts, the NCDAQ is proposing the following BACT:

Natural Gas-Fired Combustion Turbines

BACT: Dry-low NO<sub>x</sub> Combustors  
NO<sub>x</sub> Limit: 9 ppmvd NO<sub>x</sub> @ 15% O<sub>2</sub> [24-hr average]

No. 2 Fuel Oil-Fired Combustion Turbines

BACT: Water Injection  
NO<sub>x</sub> Limit: 42 ppmvd NO<sub>x</sub> @ 15% O<sub>2</sub> [24-hr average]

Compliance with the BACT emission limits will be verified through an initial stack test using a three run average.

**BACT for NO<sub>x</sub> Emissions from the Emergency Diesel Engines**

The proposed emergency engines include a 2,000 hp emergency diesel generator and a 208 hp emergency diesel engine driven firewater pump. The operation of both engines will be limited to 500 hours of operation (including testing) per consecutive 12-month period. Because of their status as emergency equipment and their expected infrequent use, the cost of post-combustion control such as SCR, is expected to be high in terms of tons of NO<sub>x</sub> removed and thus, not practical as BACT control.

According to the RBL Clearinghouse, for small and large emergency internal combustion engines, BACT alternatives include ignition timing retard (ITG), good (low NO<sub>x</sub>) engine design, the use of low sulfur, low ash fuel, and limits on the hours of operation. Southern Power proposes similar controls for both emergency diesel engines. Additionally, Southern Power recommends that NO<sub>x</sub> emissions from the emergency generator be limited to 10.9 g/hp-hr and from the emergency firewater pump to 4.4 g/hp-hr. BACT determinations support the NO<sub>x</sub> limit for the emergency firewater pump engine is BACT. The lowest limit in the RBL Clearinghouse for small internal combustion engines is 7.7 g NO<sub>x</sub>/hp-hr. However, the RBL Clearinghouse shows one determination (IA-0088)<sup>2</sup> for large internal combustion engines with a NO<sub>x</sub> limit of

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<sup>2</sup> Archer Daniels Midland, ADM Corn Processing, Cedar Rapids, IA, Emergency Generator

4.5 g/hp-hr. Additionally, NSPS, Subpart III, §60.4208 states that after December 31, 2008, owners and operators may not install emergency generator that do not meet the applicable requirements for 2007 model year engines. For 2007 model year internal combustion engines greater than 750 hp, NSPS limits combined NO<sub>x</sub> and VOC emissions to 4.7 g/hp-hr. Therefore, the following BACT applies to the emergency engines:

Emergency Generator

BACT: Ignition Timing Retard, Low NO<sub>x</sub> Engine Design, Annual Use Limits  
NO<sub>x</sub> Limit: 4.7 g/hp-hr (for NO<sub>x</sub> and VOC combined emissions)

Emergency Firewater Pump Engine

BACT: Ignition Timing Retard, Low NO<sub>x</sub> Engine Design, Annual Use Limits,  
NO<sub>x</sub> Limit: 4.4 g/hp-hr

**BACT for NO<sub>x</sub> Emissions from the Natural Gas-Fired Heater**

The proposed project includes a 4.0 million Btu per hour heater equipped with low-NO<sub>x</sub> burners fired exclusively with pipeline quality natural gas. Given the small amount of NO<sub>x</sub> emissions expected from the heater, the use of SCR or any other add-on control is not considered cost effective. Southern Power has proposed using good combustion practices, which includes the use of low-NO<sub>x</sub> burners, and pipeline quality natural gas for BACT with a NO<sub>x</sub> emission limit of 0.10 lbs/million Btu (HHV). A review of the RBL Clearinghouse indicates that the proposed control and limit represent BACT. Therefore, the following BACT applies to the natural gas heater:

BACT: Low-NO<sub>x</sub> burners and pipeline quality natural gas  
NO<sub>x</sub> Limit: 0.10 lbs/million Btu (HHV).

**5.4 BACT Analysis for CO**

Carbon monoxide (CO) is a colorless, odorless, tasteless and toxic gas produced as a by-product of incomplete combustion. CO emissions have adverse health effects and play a role in ground level ozone formation. The highest levels of CO in the outside air occur during periods of nighttime inversions when an upper layer of warm air traps CO near the ground, usually in the colder months of the year.

CO emissions from the combustion 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 combustion control to suppress CO formation and post-combustion control, such as catalytic oxidation, to remove the CO from the flue gas. Combustion control techniques, including increased fuel residence time and increased combustion zone temperature, minimize incomplete combustion and CO formation. However, because increases in thermal NO<sub>x</sub> formation are related to increases in the combustion temperature and the residence time of nitrogen at that temperature, care must be exercised when using combustion control. At higher combustion temperatures and longer residence times, NO<sub>x</sub> formation is substantially greater. Conversely, a low NO<sub>x</sub> emission rate achieved through flame temperature control (by water

injection or aggressive dry lean pre-mix) results in higher CO emissions. Thus, a balance must be established whereby the flame temperature reduction is set to achieve the lowest NO<sub>x</sub> emission rate possible while keeping CO emission rates at acceptable levels. In North Carolina, NO<sub>x</sub> is a more important pollutant to control because it is a precursor to ozone formation.

### **GOOD COMBUSTION 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.

### **CATALYTIC OXIDATION**

Catalytic oxidation is an add-on or post-combustion control used to promote the oxidation of CO to carbon dioxide (CO<sub>2</sub>) by lowering the activation energy of the reaction. Turbine exhaust gases containing both CO and O<sub>2</sub> pass through a catalyst bed (typically platinum/rhodium) and react to form CO<sub>2</sub>. Catalytic oxidation is a technically feasible option for simple cycle combustion turbines burning either natural gas or fuel oil. Control efficiencies typically range from 80 to 90 percent.

#### Economic Impact

The Permittee has conducted the cost impact analysis, using the EPA factors,<sup>3</sup> for the catalytic oxidation under two operating conditions:

- A. 2,000 hours of operation per year with natural gas-fired
- B. 1,000 hours of operation per year with natural gas and 1,000 hours of operation per year with fuel oil

The analysis assumes an 80% reduction in CO emissions. The costs of using catalytic oxidation to control CO emissions from the turbines when firing natural gas or a combination of natural gas and fuel oil are estimated at \$39,203 per ton of CO removed and \$22,402 per ton CO removed, respectively.

#### Environmental Impact

In addition to promoting the oxidation of CO, catalytic oxidation is expected to activate several other reactions. It provides the benefit of oxidizing unburned hydrocarbons and lowering VOC emissions, but it also promotes the formation of sulfuric acid and particulates. At temperatures of 1,100°F or greater, in the presence of the catalyst, almost all of the SO<sub>2</sub> in the flue gas will react to form sulfuric acid mist. Other compounds in the flue gas may oxidize to form salts, most of which are less than 10 microns in size. Thus, using catalytic oxidation may increase sulfuric acid mist and particulate emissions and impact opacity. Additionally, the disposal of spent catalyst every three to six years is an impact.

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<sup>3</sup> EPA Air Pollution Control Cost Manual, 6th ed., EPA OAQPS, RTP, NC, EPA/452/B-02-001, January 2002.

### Energy Impact

The pressure drop across the catalyst bed, typically ranging from 0.7 to 1.0 inches of water, is expected to have a substantial adverse energy impact. The pressure drop is projected to correspond to a 0.1 percent loss in power output and fuel efficiency. Southern Power anticipates a 205 KW power loss for each turbine or up to a total of 2,460,000 KW-hours lost each year. The energy cost has been taken into consideration in the economic analysis.

### **BACT for CO Emissions from the Combustion Turbines**

The use of good combustion control to enhance complete combustion and thereby, minimize CO formation, represents BACT for the proposed combustion turbines. The applicant has proposed BACT emission limits of 9 ppmvd CO @ 15% O<sub>2</sub> for natural gas combustion and 20 ppmvd CO @ 15% O<sub>2</sub> when No. 2 fuel oil is fired. The CO limits are the vendor guarantees for CCGF's proposed turbines over the range of operating loads for which the turbines are expected to be operated. However, based upon the emission data provided by Siemens, when the combustion turbines are natural gas-fired, CO emissions are 4 ppmvd @ 15% O<sub>2</sub> at 70 to 100% load. NCDAQ does not expect for CCGF to achieve lower CO limits without either increasing NO<sub>x</sub> emissions or installing oxidation catalysts. Therefore, the NCDAQ proposes the following BACT for the combustion turbines:

BACT:	Good Combustion Control
CO Limit:	4 ppmvd CO @ 15% O <sub>2</sub> (natural gas combustion @ 70 to 100% load)
	10 ppmvd CO @ 15% O <sub>2</sub> (natural gas combustion @ 60 to 70% load)
	10 ppmvd CO @ 15% O <sub>2</sub> (No. 2 fuel oil combustion @ 90 to 100% load)
	20 ppmvd CO @ 15% O <sub>2</sub> (No. 2 fuel oil combustion @ 80 to 90% load)
	30 ppmvd CO @ 15% O <sub>2</sub> (No. 2 fuel oil combustion @ 70 to 80% load)

Compliance with the BACT emission limits will be verified through an initial stack test for each fuel using a three run average. The test shall be conducted at only one load per fuel. Compliance with the emission limit at the load tested shall indicate compliance with the emission limits at the other loads.

### **BACT for CO Emissions from the Emergency Diesel Engines**

The proposed emergency engines include a 2,000 hp diesel emergency generator and a 208 hp diesel engine driven emergency firewater pump. The operation of both engines will be limited to 500 hours of operation (including testing) per consecutive 12-month period. Because of their status as emergency equipment and their expected infrequent use, the installation of post-combustion control such as catalytic oxidation, while technically feasible, is expected to be extremely costly in terms of tons of CO removed. Southern Power has proposed limiting emissions from the emergency generator and firewater pump engine to 2.5 g/hp-hr and 2.6 g/hp-hr, respectively. Both limits represent BACT and are consistent with NSPS restrictions. Southern Power plans to achieve these limits through good engine design and annual use limitation. Therefore, the NCDAQ proposes the following BACT for the emergency diesel engines:

BACT: Good engine design and annual use limitation  
CO limits: 2.5 g/hp-hr (emergency diesel generator)  
2.6 g/hp-hr (emergency firewater pump engine)

### **BACT for CO Emissions from the Natural Gas-Fired Heater**

Given the small amount of CO emissions expected from the heater, the use of catalytic oxidation or any other add-on control is not considered cost effective. Southern Power has proposed using good combustion practices as BACT with a CO emission limit of 0.08 lbs/million Btu (HHV). The proposed BACT limit is based upon EPA emission factors in AP-42. Using good combustion practices to limit CO emissions to very low levels is expected to increase NO<sub>x</sub> emissions above 0.10 lbs/million Btu. When the NO<sub>x</sub> emissions are limited to 0.10 lbs/million Btu, the BACT emission limit for CO is 0.082 lbs/million Btu. Therefore, the NCDAQ proposes the following BACT for the natural gas heater:

BACT: Good combustion practices  
CO limit: 0.08 lbs/million Btu (HHV)

### **5.5 BACT Analysis for PM/PM<sub>10</sub>**

Particulate emissions may have adverse health effects, reduce visibility, and contribute to environmental and aesthetic damage. Particulates of particle size less than 10 micrometers in diameter have been linked to respiratory irritation, aggravated asthma, chronic bronchitis, decreased lung function, irregular heartbeat, nonfatal heart attacks, and premature death. Fine particles less than 2.5 micrometers in diameter reduce visibility (haze).

Particulate emissions are the result of incomplete combustion and trace particulates and impurities in the fuel. Emissions of PM/PM<sub>10</sub> from combustion turbines are inherently low because the turbines are designed and operated to combust the fuel as completely as possible in order to attain the highest possible thermal efficiency and because they burn clean fuel. Essentially all PM emissions from gas turbines are less than 1 micron in diameter and are, therefore, within the PM<sub>10</sub> range (less than 10 micron diameter). The combustion turbines will be fueled by pipeline quality natural gas and ultra low sulfur distillate (ULSD)/low ash fuel oil. To protect the turbine blades and intricate components from small particles, Southern Power plans to filter each fuel prior to its use and thus, further minimize particulate emissions.

### **BACT for PM/PM<sub>10</sub> Emissions from the Combustion Turbines**

The RBL Clearinghouse does not list any post-combustion PM control technologies being used on combustion turbines. Add-on controls such as fabric filters and electrostatic precipitators (ESPs) are technically infeasible for combustion turbines due to high exhaust flow rates and low particulate loading inherent to turbines. Southern Power proposes the use of low-ash/low sulfur fuel and annual operational limitations as PM/PM<sub>10</sub> BACT for the proposed combustion turbines without BACT emission limits. These operational controls, which represent BACT, are expected to limit PM<sub>10</sub> emissions to less than 0.0083 lb/million Btu while firing natural gas and to 0.0646 lb/million Btu when firing fuel oil. A cost analysis is not necessary because the only technically feasible option is being proposed. Therefore, the NCDAQ proposes the following BACT:

BACT: Good Combustion Control  
PM/PM<sub>10</sub> Limit: 0.0083 lb/million Btu (natural gas combustion)  
0.0646 lb/million Btu (fuel oil combustion)

Because the PM/PM<sub>10</sub> emissions due to burning of natural gas and ultra low sulfur/low ash fuel oil in the combustion turbines are very low, performance testing is not required for PM/PM<sub>10</sub> emissions.

#### **BACT for PM/PM<sub>10</sub> Emissions from the Emergency Diesel Engines**

Operation of the proposed emergency generator and firewater pump engine will be limited to 500 hours (including testing) per consecutive 12-month period. Given the small amount of PM/PM<sub>10</sub> emissions expected from these engines, the use of fabric filters, ESPs, or any other add-on control is not considered cost effective. The RBL Clearinghouse indicates BACT is the use of low ash fuel oils and shows the most restrictive limit at 0.15 g PM<sub>10</sub> /bhp-hr. Southern Power has proposed PM limits based upon EPA emission factors in AP-42, which estimate PM/PM<sub>10</sub> emissions from emergency firewater pump engine and generator at 0.23 g/hp-hr and 0.35 g/hp-hr, respectively. However, because NSPS requires the emergency generator to be model year 2007 or later, BACT limits for this engine will be the NSPS limit of 0.15 g PM/hp-hr. Selection of an emergency generator of model year 2007 or later ensures compliance. Therefore, the NCDAQ proposes the following BACT for the emergency diesel engines:

BACT: Use of low ash fuel oils  
PM/PM<sub>10</sub> limit: 0.15 g/hp-hr (emergency diesel generator)  
0.23 g/hp-hr (emergency firewater pump engine)

#### **BACT for PM/PM<sub>10</sub> Emissions from the Natural Gas Heater**

Given the small amount of PM/PM<sub>10</sub> emissions expected from the heater, the use of fabric filters, ESPs, or any other add-on control is not considered cost effective. Southern Power recommends using pipeline quality natural gas as BACT. No BACT limit is suggested. The RBL Clearinghouse indicates BACT is the use of low ash fuels such as natural gas and shows the most restrictive limit at 0.0076 lb PM/PM<sub>10</sub>/million Btu. Based upon the fuel specifications, potential PM<sub>10</sub> emissions are estimated at 0.007 lb/million Btu. Therefore, the NCDAQ proposes the following BACT for the natural gas heater:

BACT: Use of pipeline quality natural gas  
PM/PM<sub>10</sub> limit: 0.0076 lbs/million Btu (HHV)

### **5.6 BACT Analysis for VOC**

Volatile organic compounds (VOCs) are released into the air when fuel is not completely burned. In the atmosphere, VOCs react with NO<sub>x</sub> in the presence of sunlight to form ozone. VOCs are also significant greenhouse gases via their role in creating ozone and in prolonging the life of methane in the atmosphere. Aromatic VOC compounds such as benzene, toluene, and xylene are suspected carcinogens.

VOC emissions result from incomplete combustion. Unburned hydrocarbons consist of VOCs, which contribute to ground level ozone, and methane and ethane, which do not produce ozone. VOC emissions from the combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. VOC control methods include increasing the extent of the combustion reaction and post-combustion control, such as catalytic oxidation, to remove the VOCs from the flue gas. Combustion control techniques, including increased fuel residence time and increased combustion zone temperature, minimize incomplete combustion resulting in less unreacted VOCs. However, because increases in thermal NO<sub>x</sub> formation are related to increases in the combustion temperature and the residence time of nitrogen at that temperature, care must be exercised when using combustion control. At higher combustion temperatures and longer residence times, NO<sub>x</sub> formation is substantially greater. Conversely, a low NO<sub>x</sub> emission rate achieved through flame temperature control (by water injection or aggressive dry lean pre-mix) results in higher VOC emissions. Thus, a balance must be established whereby the flame temperature reduction is set to achieve the lowest NO<sub>x</sub> emission rate possible while keeping VOC emission rates at acceptable levels.

### **GOOD COMBUSTION CONTROL**

Good combustion control practices rely on efficient operation of the combustion turbine. Emissions of VOC 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.

### **CATALYTIC OXIDATION**

Catalytic oxidation is an add-on or post-combustion control used to promote the reaction of VOC with oxygen by lowering the activation energy of the reaction. Turbine exhaust gases containing both VOCs and O<sub>2</sub> pass through a catalyst bed (typically platinum/rhodium) and react to form CO<sub>2</sub> and water. Catalytic oxidation is a technically feasible option for simple cycle combustion turbines burning either natural gas or fuel oil. Expected control efficiencies range from 40 to 50%.

#### Economic Impact

The Permittee has conducted the cost impact analysis, using the EPA factors,<sup>4</sup> for the catalytic oxidation under two operating conditions:

- A. 2,000 hours of operation per year with natural gas-fired
- B. 1,000 hours of operation per year with natural gas and 1,000 hours of operation per year with fuel oil

The analysis assumes a 40% reduction in VOC emissions. The costs of using catalytic oxidation

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<sup>4</sup> EPA Air Pollution Control Cost Manual, 6th ed., EPA OAQPS, RTP, NC, EPA/452/B-02-001, January 2002.

to control VOC emissions from the turbines when firing natural gas or a combination of natural gas and fuel oil are estimated at \$482,497 per ton of VOC removed.

#### Environmental Impact

In addition to promoting the oxidation of VOCs and CO, catalytic oxidation is expected to activate several undesirable reactions. At temperatures of 1,100°F or greater, in the presence of the catalyst, almost all of the SO<sub>2</sub> in the flue gas will react to form sulfuric acid mist. Some other compounds in the flue gas may oxidize to form salts, most of which are less than 10 microns in size. Thus, using catalytic oxidation may increase sulfuric acid mist and particulate emissions and impact opacity. Additionally, the disposal of spent catalyst every three to six years is an impact.

#### Energy Impact

The pressure drop across the catalyst bed, typically ranging from 0.7 to 1.0 inches of water, is expected to have a substantial adverse energy impact. The pressure drop is projected to correspond to a 0.1 percent loss in power output and fuel efficiency. Southern Power anticipates a 205 KW power loss for each turbine or up to a total of 2,460,000 KW-hours lost each year. The energy cost has been taken into consideration in the economic analysis.

#### **BACT for VOC Emissions from the Combustion Turbines**

The use of good combustion control to enhance complete combustion and thereby, minimize VOC formation, represents BACT for the proposed combustion turbines. The applicant has proposed BACT emission limits of 5 ppmvd VOC @ 15% O<sub>2</sub> for natural gas combustion and 1 ppmvd VOC @ 15% O<sub>2</sub> when No. 2 fuel oil is fired. Based upon data provided in the application by the turbine manufacturer, CCGF should be able to maintain VOC emissions at 1 ppmvd at 70 to 100% load and at 5 ppmvd at 60% load when firing natural gas.

NCDAQ does not expect for CCGF to achieve lower VOC limits without either increasing NO<sub>x</sub> emissions or installing oxidation catalysts. Therefore, the NCDAQ proposes the following BACT for the combustion turbines firing either natural gas or No. 2 fuel oil:

BACT: Good Combustion Control  
VOC Limit: 1 ppmvd VOC @ 15% O<sub>2</sub> (natural gas combustion @ 70 to 100% load)  
5 ppmvd VOC @ 15% O<sub>2</sub> (natural gas combustion @ 60 to 70% load)  
1 ppmvd CO @ 15% O<sub>2</sub> (No. 2 fuel oil combustion @ 70 to 100% load)

Compliance with the BACT emission limits will be verified through an initial stack test using a three run average for each fuel. The test shall be conducted at only one load per fuel. Compliance with the emission limit at the load tested shall indicate compliance with the emission limits at the other loads.

#### **BACT for VOC Emissions from the Emergency Diesel Engines**

The proposed emergency engines include a 2,000 hp diesel emergency generator and a 208 hp diesel engine driven emergency fire pump. The operation of both engines will be limited to 500 hours of operation (including testing) per consecutive 12-month period. Because of their status as

emergency equipment and their expected infrequent use, the installation of post-combustion control such as catalytic oxidation, while technically feasible, is expected to be extremely costly in terms of tons of VOC removed and thus, not practical as BACT control. Southern Power has proposed limiting emissions from the diesel emergency generator and firewater pump engine to 0.29 g/hp-hr and 1.1 g/hp-hr, respectively through good engine design. Both limits are considered BACT. Therefore, the NCDAQ proposes the following BACT for the emergency diesel engines:

BACT: Good engine design and annual use limitation  
VOC limits: 0.29 g/hp-hr (emergency diesel generator)  
1.1 g/hp-hr (emergency firewater pump engine)

#### **BACT for VOC Emissions from the Natural Gas-Fired Heater**

Given the small amount of VOC emissions expected from the heater, the use of catalytic oxidation or any other add-on control is not considered cost effective. Southern Power has proposed using good combustion practices as BACT with a CO emission limit of 0.005 lbs/million Btu. The proposed BACT limit is based upon vendor specifications. Therefore, the NCDAQ proposes the following BACT for the natural gas heater:

BACT: Good combustion practices  
VOC limit: 0.0055 lbs/million Btu (HHV)

### **5.7 BACT Analysis for SO<sub>2</sub> (State-only Requirement)**

The NC SIP requirement, 15A NCAC 2D .0530 (h), requires new electric generating units such as the proposed combustion turbines to install BACT for NO<sub>x</sub> and SO<sub>2</sub> even if the projected emissions are less than the significance threshold. This BACT requirement is a “state-only” requirement. SO<sub>2</sub> emissions are produced by the combustion of sulfur-containing fuels. Generally, all of the sulfur compounds contained in the fuels will oxidize to SO<sub>2</sub>. Southern Power plans to minimize SO<sub>2</sub> emissions with the selection of low sulfur fuels including natural gas and ultra low sulfur distillate fuel oil. The maximum SO<sub>2</sub> emissions from the proposed combustion turbines, heater, emergency generator, and emergency fire-water pump are approximately 14.40 tons per year and well below the significance threshold of 40 tpy.

#### **SO<sub>2</sub> Control Alternatives**

The RBLC Clearinghouse data indicates that low sulfur fuel is the only available SO<sub>2</sub> control alternative for combustion turbines. Add-on controls such as flue gas desulfurization (FGD) are not technically feasible for combustion turbines. Southern Power proposes to use the pipeline quality natural gas with a low sulfur content of 0.2 grain/100 sft<sup>3</sup> and ultra low sulfur distillate (ULSD) fuel oil with a 0.0015% by weight sulfur content as BACT to minimize SO<sub>2</sub> emissions. Fuels with sulfur concentrations lower than those proposed are not commercially available. Moreover, onsite refinement to further reduce sulfur concentrations is not expected to be cost effective since fuel suppliers have already reduced sulfur to the lowest practical levels.

## SO<sub>2</sub> BACT Determination

The use of pipeline quality natural gas containing 0.2 grain/100 sft<sup>3</sup> and USLD fuel oil with a 0.0015% by weight sulfur content to control of SO<sub>2</sub> from the combustion turbines is considered BACT. EPA emission factors contained in AP-42 indicate the use of these fuels will result in 0.0006 lb/million Btu of sulfur emissions when firing natural gas and 0.0015 lb/million Btu of sulfur emissions when firing ULSD fuel. Using the above sulfur content for natural gas, the SO<sub>2</sub> BACT emission limit can be estimated as 0.0006 lb/million Btu. Therefore, the NCDAQ proposes the following BACT for the combustion turbines:

BACT: Use of pipeline quality natural gas containing 0.2 grain/100 sft<sup>3</sup> and USLD fuel oil with a 0.0015% sulfur content.  
 SO<sub>2</sub> Limit: 0.0006 lb/million Btu (natural gas combustion)  
 0.0015 b/million Btu (fuel oil combustion)

Compliance will be verified using the sulfur content of the natural gas and USLD fuel oil in the valid purchase contracts, tariff sheets, or transportation contracts.

## 5.8 BACT Summary

The following Table presents a summary of the proposed BACT determinations for various pollutants for the emissions from six single cycle combustion turbines, one emergency diesel generator, one emergency diesel fire-water pump, and one natural gas fired heater as proposed by DAQ for approval.

**Table 5.8-1 Best Available Control Technologies**

Emission Source	Pollutant	Fuel	Emission Limits <sup>1 to 4</sup>	Control Technology
six natural gas/No. 2 fuel oil-fired simple cycle combustion turbines (ID Nos. ES1 through ES6)	NO <sub>x</sub> (as NO <sub>2</sub> )	natural gas	9 ppmvd <sup>2</sup> at 15% O <sub>2</sub> [24-hour average] <sup>3</sup>	dry-low NO <sub>x</sub> combustors
		fuel oil	42 ppmvd <sup>2</sup> at 15% O <sub>2</sub> [24-hour average] <sup>3</sup>	water injection
	CO <sup>4</sup>	natural gas	4 ppmvd at 15% O <sub>2</sub> at 70 to 100% load	good combustion control practices
			10 ppmvd at 15% O <sub>2</sub> at 60 to <70% load	
		fuel oil	10 ppmvd at 15% O <sub>2</sub> at 90 to 100% load	good combustion control practices
			20 ppmvd at 15% O <sub>2</sub> at 80 to <90% load 30 ppmvd at 15% O <sub>2</sub> at 70 to <80% load	
	VOC (as CH <sub>4</sub> ) <sup>4</sup>	natural gas	1 ppmvd at 15% O <sub>2</sub> at 70 to 100% load	good combustion control practices

<b>Emission Source</b>	<b>Pollutant</b>	<b>Fuel</b>	<b>Emission Limits<sup>1 to 4</sup></b>	<b>Control Technology</b>
			5 ppmvd at 15% O <sub>2</sub> at 60 to <70% load	
		fuel oil	10 ppmvd at 15% O <sub>2</sub>	good combustion control practices
	PM/PM <sub>10</sub> (filterable and condensable)	natural gas	0.0083 lb/million Btu	good combustion control practices and use of pipeline quality natural gas containing a maximum of 0.2 grain per 100 square feet sulfur content
		fuel oil	0.0646 lb/million Btu	good combustion control practices and use of ultra-low sulfur No. 2 fuel oil containing a maximum of 0.0015% by weight (15ppm) sulfur content
emergency generator (ID No. ES7)	NO <sub>x</sub> and VOC combined	fuel oil	4.7 g/hp-hr	ignition timing retard and low NO <sub>x</sub> engine design
	CO	fuel oil	2.5 g/hp-hr	good combustion control practices
	VOC (as CH <sub>4</sub> )	fuel oil	0.29 g/hp-hr	good combustion control practices and annual use limits
	PM/PM <sub>10</sub> (filterable and condensable)	fuel oil	0.15 g/hp-hr	use of ultra-low sulfur No. 2 fuel oil containing a maximum of 0.0015% by weight (15ppm) sulfur content and annual use limits
emergency fire water pump engine (ID No. ES8)	NO <sub>x</sub> (as NO <sub>2</sub> )	fuel oil	4.4 g/hp-hr	ignition timing retard, low NO <sub>x</sub> engine design, and good combustion control
	CO	fuel oil	2.6 g/hp-hr	good combustion control practices
	VOC (as CH <sub>4</sub> )	fuel oil	1.1 g/hp-hr	good combustion control practices
	PM/PM <sub>10</sub> (filterable and condensable)	fuel oil	0.23 g/hp-hr	use of ultra-low sulfur No. 2 fuel oil containing a maximum of 0.0015% by weight (15ppm) sulfur content
gas heater	NO <sub>x</sub> (as NO <sub>2</sub> )	natural gas	0.10 lb/million Btu	low NO <sub>x</sub> burners and

Emission Source	Pollutant	Fuel	Emission Limits <sup>1 to 4</sup>	Control Technology
(ID Nos. ES9)				good combustion control practices
	CO	natural gas	0.08 lb/million Btu	good combustion control practices
	VOC (as CH <sub>4</sub> )	natural gas	0.005 lb/million Btu	good combustion control practices
	PM/PM <sub>10</sub> (filterable and condensable)	natural gas	0.0076 lb/million Btu	pipeline quality natural gas

1. BACT emission limits shall apply to each source (ID Nos. ES1 through ES9) at all times except during the following: Emissions resulting from start-up, shutdown or malfunction above those listed in the table above are permitted provided that optimal operational practices are adhered to and periods of excess emissions are minimized. For the simple cycle combustion turbines (ID Nos. ES1 through ES6), periods of excess emissions due to start-up and/or shutdown or operation below 60% load on natural gas / 70% load on fuel oil shall not exceed two hours in any 24-hour block period beginning at midnight. Start-up is defined as the period from initial firing to 60% load on natural gas / 70% load on fuel oil. Shutdown is defined as the period from 60% load on natural gas / 70% load on fuel oil to flame out.
2. ppmvd = parts per million by volume on a dry basis at 15% O<sub>2</sub>.
3. 24-hour rolling average is calculated using only actual operating hours (periods of zero emissions when not operating are not included).
4. Compliance with the BACT limits shall be based on a 3-run average of a stack test. Any use of continuous emission monitoring systems data for demonstrating compliance with BACT for any pollutants will require reevaluation of applicable BACT limits.

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):

**Table 5.8-2 NAAQS Compliance**

EMISSION SOURCE	POLLUTANT	EMISSION LIMITS			
		Annual (tons/yr)	24-hour (lbs/24-hr)	8-hour (lbs/8-hr)	1-hour (lbs/hr)
All emission sources	nitrogen oxides (as nitrogen dioxide)	1,319	-	-	-
	particulates/PM-10 (filterable and condensable both)	235	3,863	-	-
	carbon monoxide	-	-	5,716	715

\* Tons per consecutive 12-month period based on a maximum 2,000 operating hours per each combustion turbine of which ULS No. 2 fuel oil is fired for a maximum of 1,000 hours, and a maximum of 500 operating hours for each emergency diesel engine.

## **SECTION 6.0 AIR QUALITY IMPACT ANALYSIS**

### **6.1 Modeling Analysis**

PSD regulations [40 CFR 51.166 (k)] require an applicant to perform an ambient impact analysis to demonstrate, 1) that no National Ambient Air Quality Standard (NAAQS) will be exceeded at any location and during any time period where the proposed new source or modification will have significant impact; and 2) that the proposed new sources or modification, in combination with other increment-affecting sources, will not cause any allowable PSD increment to be exceeded. NO<sub>x</sub>, CO, PM/PM-10, and VOCs are all NAAQS pollutants, which exceed the PSD significance level, thus requiring evaluation.

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 description of the modeling and modeling methodology is described below.

### **6.2 Preliminary Impact Air Quality Modeling Analysis**

An air quality preliminary impact analysis was conducted for NO<sub>x</sub>, CO, and PM<sub>10</sub>. The modeled result, High-First-High (H1H), was then compared to applicable PSD 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. Southern Power evaluated significant emissions of each pollutant using the AERMOD<sup>5</sup> model (AERMIC Model, USEPA 2004), based on five years (1988-1992) of National Weather Service surface (Charlotte, NC; Douglas International Airport) and upper air (Greensboro, NC; Greensboro-Winston Salem Airport) meteorological data and using an adequate receptor array beginning at the fence line. Modeling was initially conducted for four combustion turbine operating loads (100% load with evaporative cooling, 100% without evaporative cooling, 80%, and 60%), three ambient temperatures (100 deg F, 65 deg F, 0 deg F) and two fuels (natural gas and ULSD fuel oil). The modeling reflected the following operational restrictions and assumptions:

- The operation of the six combustion turbines is limited to a combined maximum of 12,000 hours per year (26,520,000 million Btu's).

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<sup>5</sup> The American Meteorological Society/EPA Regulatory Model Improvement Committee (AERMIC) developed AERMOD as a replacement to the Industrial Source Complex (ISC) model. With the AERMOD model, air dispersion calculations consider planetary boundary layer meteorology and include Plume Rise Model Enhancement (PRIME) building downwash algorithms

- The operation of the six combustion turbines while firing fuel oil is limited to a combined maximum of 6,000 hours per year (12.744,000 million Btu's).
- The operation six combustion turbines, while firing fuel oil, is limited to a combined maximum of 54 hours per day (114,966 million Btu's).
- No natural gas shall be fired in the turbines for the calendar day if total fuel oil operations exceed 42 combined turbine hours (89,418 million Btu's) in that calendar day.
- The emergency generator and fire-water pump are expected to operate one hour per week and 52 hours per year under non-emergency conditions (warranty testing).
- The fuel gas heater will operate 8,760 hours per year.

Southern Power modeled a composite “worst-case” set of emission factors to conservatively calculate ground-level pollutant concentrations. As shown in Table 6.2-1, the highest projected impact of each criteria pollutant from the proposed facility is less than its respective Class II SIL. Being that all criteria pollutants are less than the Class II SILs, the proposed facility is considered in compliance with applicable increments.

**Table 6.2-1 Class II Significant Impact Results (ug/m<sup>3</sup>)**

<b>Pollutant</b>	<b>Averaging Period<sup>1</sup></b>	<b>Facility Maximum Impact</b>	<b>Class II Significant Impact</b>
NO <sub>x</sub>	Annual	.95	1
PM10	24-hour	4.74	5
	Annual	.13	1
CO	1-hour	375.26	2000
	8-hour	50.84	500

## SECTION 7.0

### ADDITIONAL IMPACT ANALYSES

An additional impacts analysis was performed to determine air pollution impacts on growth, vegetation, soils, and local visibility from the proposed construction and operation of the Cleveland County Generating Facility. The additional impact analysis focused on the potential effects of NO<sub>x</sub> as it is the pollutant with the highest emissions.

NO<sub>x</sub> together with VOCs in the atmosphere leads to the formation of ozone (O<sub>3</sub>). A literature search was performed to identify information on the potential adverse impacts of NO<sub>x</sub> and O<sub>3</sub> in general. Based on the findings, no adverse impacts to soils, vegetation, or local visibility are expected from the proposed facility expansion.

#### 7.1 Growth Impact Analysis

The unemployment rate in Cleveland County has doubled in the past year, reaching 12% as of December 2008. The need for economic and job growth is critical to this area. The proposed facility will benefit the county by employing about 10 personnel on a permanent basis and 100 to 150 temporarily workers during the construction phase. Southern Power plans to hire from the local community and anticipates no need for additional infrastructures. An increase in secondary emissions associated with non-project activities is not expected.

#### 7.2 Effects on Vegetation

The applicant concluded that there would be no significant adverse impact on the vegetation in and around the facility. The health and well being of vegetative ecosystems are dependent on many environmental (e.g., precipitation, insects, disease) and anthropogenic factors (e.g. logging, urban sprawl, pollution). All of these factors combined influence the overall health and productivity of vegetative ecosystems, including croplands and forests. NO<sub>x</sub> and O<sub>3</sub> are the two pollutants most likely to harm vegetation. The effects of NO<sub>x</sub> and O<sub>3</sub> on individual plants and the factors that modify plant response to these compounds are complex and vary with species, environmental conditions, and soil and nutrient conditions. Factors such as genetic susceptibility, light, temperature, relative humidity, soil nutrients, and soil moisture may influence the uptake of NO<sub>x</sub> and O<sub>3</sub>. NO<sub>x</sub> enters the leaves of plants through openings known as stomata. Its presence in significant quantities may result in biochemical changes such as visible foliar injury, premature senescence, increased leaf abscission, and altered plant growth and yield as well as physiological effects including changes in photosynthesis, specific enzymes, metabolic pools, and the translocation of photosynthesis. High gaseous concentrations of NO<sub>x</sub> may lead to poor chlorophyll production and tissue damage. Symptoms of air pollution-related damage from NO<sub>x</sub> and O<sub>3</sub> include reduction in growth rates, reduction in reproductive rates, direct foliar damage, and mortality. The EPA publication entitled "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" (EPA 1980) provides acute and chronic thresholds exposure levels for air pollutants, which may impact sensitive vegetation. A comparison of NO<sub>x</sub> and CO concentrations to these thresholds, as shown below in Table 7.2-1, supports the

applicant's claim that the proposed project will have no damaging effect on natural vegetation and crops.

**Table 7.2-1 Comparison of Pollutant Impact to EPA Criteria for Impacts on Natural Vegetation and Crops**

<b>Pollutant</b>	<b>Averaging Period<sup>1</sup></b>	<b>Facility Maximum Impact (micrograms/m<sup>3</sup>)</b>	<b>Minimum Impact Level for Effect on Sensitive Plants (micrograms/m<sup>3</sup>)</b>
NO <sub>x</sub>	4-hour	287.45	3,760
	8-hour	146.03	3,760
	1-month	9.46	564
	1-year	3.47	94
CO	1-week	19.16*	1,800,000

### 7.3 Effects on Soil

The soils at and around the site are gently sloping to steep, moderately deep to very deep, well drained soils that have a loamy surface layer and a clayey subsoil on uplands.<sup>6</sup> The applicant concluded that there would be no significant adverse impact on the soil. Given that Cleveland County is in attainment for NO<sub>2</sub> and unclassified for SO<sub>2</sub>, acid rain (formed when NO<sub>x</sub> or SO<sub>2</sub> reacts with water vapor and sunlight) is expected to be insignificant and have negligible effect on soil pH. The applicant noted that the greatest potential impact to the soils would be the secondary effect resulting from the loss of vegetation. Damage to the plant ground cover could increase soil temperature, moisture stress, and/or increase runoff and soil erosion. As demonstrated in Section 7.2, the maximum ground level concentrations of NO<sub>x</sub> and CO are well below the vegetation impact thresholds. Therefore, it is reasonable to assume the proposed facility will not degrade soil quality.

### 7.4 Effects on Local Visibility

NO<sub>x</sub> and fine particulates contribute to atmosphere discoloration and/or haze. NO<sub>x</sub> consists of NO<sub>2</sub>, a reddish brown gas, and other nitrogen oxides that react with atmospheric oxygen to form NO<sub>2</sub>. Particulate emissions, below 10 microns in size, are a leading cause of decreased visibility. Because the proposed facility will emit these pollutants in significant quantities, Southern Power has evaluated the impact of potential NO<sub>x</sub> and PM<sub>10</sub> emissions on visibility through Class I and II visibility impairment modeling.

<sup>6</sup> U.S. Department of Agriculture, Cleveland County Soil Survey.

### 7.4.1 Class II Visibility Impairment Analysis

Southern Power performed a visibility analysis using the EPA VISCREEN model to evaluate “worst-case” atmospheric discoloration in nearby Class II areas resulting from potential NO<sub>x</sub> and PM<sub>10</sub> emissions from the proposed CCGF. The closest Class I area is Linville Gorge Wilderness Area, located 85 km northwest from the proposed generating facility. To be conservative, Southern Power ran the VISCREEN model at a distance of 75 km. The maximum values of atmospheric discoloration or plume perceptibility ( $\Delta E$ ) and plume contrast (Cp) are 1.957 and 0.005 respectively and are below the visibility impairment thresholds of 2.0 and 0.05, respectively. Thus, the analysis indicates the proposed project will not result in significant visibility impairment. Furthermore, there were no specially protected visibility areas within the North Carolina modeled area. The DAQ Air Quality Analysis Branch contacted South Carolina’s Bureau of Air Quality and determined that South Carolina has no requirement for Class II visibility analysis when the project modeling impact is below the SIL, as is the case for CCGF.

### 7.4.2 Class I Increment Analysis/ Air Quality Related Value (AQRV) Regional Haze Impact Analysis

A Class I area SIL analysis was used to evaluate NO<sub>x</sub> and PM<sub>10</sub> (no SIL or increment is defined for CO) at a 100% operating load and at varying fuel combinations for impacts at the nearest Class I areas including Linville Gorge Wilderness Area, Shining Rock Wilderness, and Great Smokey Mountains National Park. Southern Power submitted CALPUFF (version 5.8) modeling, which included POSTUTIL and CALPOST, to demonstrate the impact of potential NO<sub>x</sub> and PM<sub>10</sub> emissions on the regional haze change (deciview (dv)) threshold at the three Class I sites. The modeling was conducted using the VISTAS-processed, 3-year meteorology dataset from 2001 to 2003, an initial 4 km receptor grid encompassing all three Class I areas, and a refined 1 km receptor grid resolution including only the Linville Gorge Class I area. The finer grid includes a more accurate characterization of the terrain between CCGF and Linville Gorge.

The modeling assumed all NO<sub>x</sub> emissions were converted to NO<sub>2</sub> to ensure maximum impacts were evaluated and included the monthly average of available hourly background O<sub>3</sub> data from the closest monitors and the monthly average ammonia background levels. The maximum impacts shown from the analysis indicate the facility will have no significant impact on NO<sub>x</sub> and PM<sub>10</sub> increments at all assessed PSD Class I areas. Therefore, no further PSD increment analysis is required.

**Table 7.4.2-1 CALPUFF Results (ug/m<sup>3</sup>)**

Pollutant	Averaging Period	Class I Area SIL	Class I Maximum Impact	% of SIL
Linville Gorge Wilderness Area				
NO <sub>x</sub>	Annual	0.1	0.00444	4.4
PM <sub>10</sub>	24-hr	0.32	0.177	55.3
	Annual	0.16	0.00155	<1

<b>Pollutant</b>	<b>Averaging Period</b>	<b>Class I Area SIL</b>	<b>Class I Maximum Impact</b>	<b>% of SIL</b>
<b>Shining Rock Wilderness Area</b>				
NO <sub>x</sub>	Annual	0.1	0.00279	2.8
PM <sub>10</sub>	24-hr	0.32	0.1165	36.4
	Annual	0.16	0.000916	<1
<b>Great Smoky Mountains National Park</b>				
NO <sub>x</sub>	Annual	0.1	0.00126	1.3
PM <sub>10</sub>	24-hr	0.32	0.100	31.3
	Annual	0.16	0.0005	<1

#### **7.4.2.1 Visibility Impacts Under 15A NCAC 2Q .0530(t)**

Because the Class I increment was not exceeded the project was determined to not affect Class I areas in North Carolina.

#### **7.5 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.

# **APPENDIX A**

## **Draft Permit**

**APPENDIX B**

**Public Notice**

## APPENDIX C

### RBLC NCDAQ Search Summary

NC DAQ searched the RACT/BACT/LAER (RBL) Clearinghouse for the time period from January 1, 2003 to present, to identify and evaluate the current BACT determinations for NO<sub>x</sub>, PM/PM<sub>10</sub>, CO, and VOC emissions from simple cycle combustion turbines, natural gas-fired heaters, and diesel emergency engines. A brief summary of findings of this search is included below:

#### **Natural Gas-Fired Simple Cycle Combustion Turbines (no waste heat recovery) > 25 MW**

##### **NO<sub>x</sub>**

The RBL Clearinghouse shows dry low-NO<sub>x</sub> (DLN) combustors as the primary method for controlling NO<sub>x</sub> emissions from natural gas-fired simple cycle CTGs. With DLN, the lowest achievable NO<sub>x</sub> emissions from CTG's are 9 ppm at 15 percent O<sub>2</sub>. The BACT determinations also list selective catalytic reduction (SCR) as the method of NO<sub>x</sub> control for two 50 MW natural gas fired CTGs at the City of Tallahassee Arvah B. Hopkins Generating Station and for two 108 MW natural gas-fired CTGs at the Fredonia Energy Station in Mount Vernon, Washington. For these facilities, the NO<sub>x</sub> BACT limit is 5 ppm at 15 percent O<sub>2</sub>.

##### **CO**

The RBL Clearinghouse shows good combustion practices as the primary method for controlling CO emissions from natural gas-fired simple cycle CTGs. With good combustion practices, five facilities maintain CO in the flue gas at or below 9 ppm at 15 percent O<sub>2</sub>. The lowest achievable CO emissions are 8 ppm at 15 percent O<sub>2</sub>. The BACT determinations also list catalytic oxidation as the method of CO control for a 195 MW natural gas-fired CTG at the P.L. Bartow Power Plant in Pinellas County, Florida and one 48.7 MW natural gas fired CTG at EI Colton, LLC in Colton, California. CO limits are 4.1 ppm at 15 percent O<sub>2</sub> for the P.L Bartow Power Plant and 6 ppm at 15% O<sub>2</sub> for the EI Colton facility.

##### **PM/PM<sub>10</sub>**

The RBL Clearinghouse lists clean fuel and good combustion as the most rigorous control used to minimize emissions from natural gas-fired simple cycle CTGs. The clean fuel has a low ash and low sulfur content. It is difficult to determine the lowest achievable PM<sub>10</sub> emissions as most BACT determinations show the PM<sub>10</sub> limit in pounds per hour. The lowest PM<sub>10</sub> limit in terms of lbs/MMBtu is 0.008.

##### **VOC**

The RBL Clearinghouse shows good combustion practices as the primary method for controlling VOC emissions from natural gas-fired simple cycle CTGs. With good combustion practices, the BACT limits range from 1.2 to 6 ppm at 15 percent O<sub>2</sub>. The EI Colton facility in Colton, California uses catalytic oxidation to maintain VOC emissions at or below 2 ppm at 15% O<sub>2</sub>.

## **No. 2 Fuel Oil-Fired Simple Cycle Combustion Turbines (no waste heat recovery) > 25 MW**

### **NO<sub>x</sub>**

The RBL Clearinghouse shows water injection as the primary method for controlling NO<sub>x</sub> emissions from fuel oil-fired simple cycle CTGs. With water injection, several facilities maintain NO<sub>x</sub> emissions from CTG's at or below 42 ppm at 15 percent O<sub>2</sub>. One BACT determinations also list selective catalytic reduction (SCR) as the method of NO<sub>x</sub> control for two 50 MW natural gas-fired CTGs at the City of Tallahassee Arvah B. Hopkins Generating Station. For this facility, the NO<sub>x</sub> BACT limit is 5 ppm at 15 percent O<sub>2</sub>.

### **CO**

The RBL Clearinghouse shows good combustion practices as the primary method for controlling CO emissions from fuel oil-fired simple cycle CTGs. The BACT determinations also list catalytic oxidation as the method of CO control for a 195 MW No. 2 fuel oil-fired CTG at the P.L. Bartow Power Plant in Pinellas County, Florida and the 35 MW fuel oil-fired CTGs at TS Power Plant in Eureka County, Nevada. CO limits are 6 ppm at 15 percent O<sub>2</sub> for the TS Power Plant and 8 ppm at 15% O<sub>2</sub> for the P.L Bartow Power Plant.

### **PM/PM<sub>10</sub>**

The RBL Clearinghouse list clean fuel and good combustion as the most rigorous control used to minimize emissions from fuel oil-fired simple cycle CTGs. The most restrictive fuel is ultra low sulfur distillate fuel containing little ash or other contaminants. It is difficult to determine the most stringent PM<sub>10</sub> limit as most BACT determinations show the PM/PM<sub>10</sub> limit in pounds per hour. The lowest PM<sub>10</sub> limit in terms of lbs/MMBtu is 0.008.

### **VOC**

The RBL Clearinghouse shows good combustion practices as the primary method for controlling VOC emissions from fuel oil-fired simple cycle CTGs. With good combustion practices, the BACT limits range from 2.5 to 16 ppm at 15 percent O<sub>2</sub>. None of the facilities listed require catalytic oxidation for BACT.

## **Emergency Diesel Generator**

### **NO<sub>x</sub>/PM/PM<sub>10</sub>/CO/VOC**

The RBL Clearinghouse lists sixteen BACT determinations for emergency diesel generators rated at 500 HP or greater. Control technologies for each regulated pollutant include limiting the hours of operation, good combustion practices, good engine design, and the use of low sulfur/low ash fuel oil or ULS diesel fuel. Injection timing retardation is also shown as BACT for NO<sub>x</sub> and CO. The Archer Daniel Midland processing plant in Cedar Rapids, Michigan has the most restrictive BACT emission limits. Their BACT limits are listed below:

PM/PM <sub>10</sub>	0.1500 G/BHP-H (0.00033 LB/BHP-H) AVERAGE OF 3 TEST RUNS
NO <sub>x</sub>	4.5000 G/BHP-H (0.0099 LB/BHP-H) AVERAGE OF 3 TEST RUNS
VOC	0.3000 G/BHP-H (0.00066 LB/BHP-H) AVERAGE OF 3 TEST RUNS

CO 2.6000 G/BHP-H (0.0057 LB/BHP-H) AVERAGE OF 3 TEST RUNS

**BACT DETERMINATIONS FOR "LARGE EMERGENCY INTERNAL COMBUSTION ENGINES > 500 HP" 17.110**

**LC ID: NC-0112 and NC-0113**

**Corporate/Company:** NUCOR STEEL

**Facility Name:** NUCOR STEEL

**Process:** DIESEL FIRED EMERGENCY GENERATORS AND DIESEL FIRED EMERGENCY WATER PUMPS

**NO BACT EMISSION LIMITS**

OPERATION LIMITED TO 100 HOURS OF OPERATION FOR EACH EMERGENCY GENERATOR AND WATER PUMP PER 12 MONTH PERIOD

**RBLC ID: NY-0101**

**Corporate/Company:** CORNELL UNIVERSITY

**Facility Name:** CORNELL COMBINED HEAT & POWER PROJECT

**Process:** EMERGENCY DIESEL GENERATORS (2)

**NO BACT EMISSION LIMITS**

ULTRA LOW SULFUR DIESEL AT 15 PPM S.

**RBLC ID: MD-0037**

**Corporate/Company:** MEDIMMUNE, INC.

**Facility Name:** MEDIMMUNE FREDERICK CAMPUS

**Process:** THREE (3) DIESEL (NO. 2 FUEL OIL) FIRED, EMERGENCY GENERATORS EACH RATED AT 2500 KILOWATTS (3604 BRAKE HORSEPOWER)

**Emission Limit 1:** NO<sub>x</sub> 6.0600 G/HP-H

TOTAL OPERATING HOURS, INCLUDING HOURS USED FOR MAINTENANCE AND TESTING, SHALL NOT EXCEED 500 HOURS IN ANY ROLLING 12-MONTH PERIOD FOR EACH OF THE THREE (3) EMERGENCY GENERATORS. ALSO, TOTAL NOX EMISSIONS FROM THE FOUR (4) BOILERS AND THE FIVE (5) GENERATORS THAT ARE PART OF THIS PROJECT SHALL NOT EXCEED 56 TONS IN ANY ROLLING 12-MONTH PERIOD.

**RBLC ID: LA-0219**

**Corporate/Company:** CREOLE TRAIL LNG, LP

**Facility Name:** CREOLE TRAIL LNG IMPORT TERMINAL

**Process:** DIESEL EMERGENCY GENERATOR NOS. 1 & 2; 2168.00 HP EA

PM: GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL

NO<sub>x</sub>:/CO: GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)

VOC: GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN

**Emission Limit 1:** PM 0.690 LB/H HOURLY MAXIMUM

**Emission Limit 2:** NOx 37.950 LB/H HOURLY MAXIMUM  
**Emission Limit 3:** CO 12.240 LB/H HOURLY MAXIMUM  
**Emission Limit 4:** VOC 1.670 LB/H HOURLY MAXIMUM  
LIMITED TO 500 HR/YR

**RBLC ID: IA-0088**

**Corporate/Company:** ARCHER DANIELS MIDLAND

**Facility Name:** ADM CORN PROCESSING - CEDAR RAPIDS

**Process:** EMERGENCY GENERATOR

**P2/Add-on** NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFIED.  
**Description:** ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.

**Emission Limit 1:** PM./PM10 0.1500 G/BHP-H AVERAGE OF 3 TEST RUNS  
**Emission Limit 2:** NOx 4.5000 G/BHP-H AVERAGE OF 3 TEST RUNS  
**Emission Limit 3:** VOC 0.3000 G/BHP-H AVERAGE OF 3 TEST RUNS  
**Emission Limit 4:** CO 2.6000 G/BHP-H AVERAGE OF 3 TEST RUNS  
PM LIMIT INCLUDES BOTH FILTERABLE AND CONDENSABLE FRACTIONS

**RBLC ID: MN-0071**

**Corporate/Company:** MINNESOTA MUNICIPAL POWER AGENCY

**Facility Name:** FAIRBAULT ENERGY PARK

**Process:** EMERGENCY GENERATOR 1750.00 KW

**Emission Limit 1:** PM./PM10 0.0004/.0007 LB/HP-H 3 HOUR AVERAGE  
**Emission Limit 2:** NOx 0.0240 LB/HP-H 3 HOUR AVERAGE  
**Emission Limit 3:** VOC 0.0007 LB/HP H 3 HOUR AVERAGE  
**Emission Limit 4:** CO 0.0055 LB/HP H 3 HOUR AVERAGE  
EXCEPT SSM. 10 HOUR/DAY OPERATING LIMIT

**RBLC ID: OK-0118**

**Corporate/Company:** WESTERN FARMERS ELECTRIC COOP

**Facility Name:** HUGO GENERATING STA

**Process:** EMERGENCY DIESEL INTERNAL COMBUSTION ENGINES

**P2/Add-on** USE OF LOW SULFUR NO.2 FUEL OIL COMBINED WITH  
**Description:** GOOD COMBUSTION PRACTICES AND LIMITED ANNUAL OPERATION

THERE ARE NO EMISSION LIMITS FOR THE EMERGENCY DIESEL ENGINES (BACKUP GENERATOR AND FIRE WATER PUMP). BACT FOR SO2 WAS OF LOW SULFUR FUEL (NO MORE THAN 0.5% BY WEIGHT SULFUR CONTENT) AND GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF OPERATION FOR ALL OTHER POLLUTANTS.

**RBLC ID: LA-0211**

**Corporate/Company:** MARATHON PETROLEUM CO LLC

**Facility Name:** GARYVILLE REFINERY

**Process:** EMERGENCY GENERATORS 1341 HP & 671 HP  
GENERATORS PERMITTED FOR 182 H/YR EA.

USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS

<b>Emission Limit 1:</b> PM/PM10	0.0022 LB/HP-H ANNUAL AVERAGE
<b>Emission Limit 2:</b> NOx	0.0310 LB/HP-H ANNUAL AVERAGE
<b>Emission Limit 3:</b> VOC	0.0025 LB/HP-H ANNUAL AVERAGE
<b>Emission Limit 4:</b> CO	0.0067 LB/HP-H ANNUAL AVERAGE

**RBLC ID: AZ-0046**

**Corporate/Company:** ARIZONA CLEAN FUELS YUMA LLC

**Facility Name:** ARIZONA CLEAN FUELS YUMA

**Process:** EMERGENCY GENERATOR

**Process:** NO. 2 DIESEL FUEL EMERGENCY GENERATOR 10.9  
MMBTU/HR

THE ENGINE MUST BE CERTIFIED BY THE MANUFACTURER TO MEET EMISSION  
LIMITS.

<b>Emission Limit 1:</b> PM	0.020 G/KW
<b>Emission Limit 2:</b> NOx	6.400 G/KW
<b>Emission Limit 3:</b> CO	3.500 G/KW

**RBLC ID: WA-0328**

**Corporate/Company:** BP WEST COAST PRODUCTS, LLC

**Facility Name:** BP CHERRY POINT COGENERATION PROJECT

**Process:** EMERGENCY GENERATOR; 1.5 MW, DIESEL FUEL  
THE ENGINE MUST BE NEW AND MUST SATISFY THE  
FEDERAL ENGINE STANDARDS OF 40 CFR 89 FOR YEAR  
OF PURCHASE

**RBLC ID: OH-0275**

**Corporate/Company:** CINERGY

**Facility Name:** PSI ENERGY-MADISON STATION

**Process:** 17.21 MMBTU/H EMERGENCY DIESEL GENERATOR, 2  
EACH GENERATOR RESTRICTED TO 499 H/YR OF  
OPERATION

**RBLC ID: OH-0254**

**Corporate/Company:** DUKE ENERGY NORTH AMERICA

**Facility Name:** DUKE ENERGY WASHINGTON COUNTY LLC

**Process:** EMERGENCY DIESEL-FIRED GENERATOR

LOW SULFUR FUEL, COMBUSTION CONTROL

**Emission Limit 1:** PM. 0.4100 G/BHP-H

**Emission Limit 2:** NOx 7.000 G/BHP-H

**Emission Limit 3:** VOC 1.000 G/BHP-H

**Emission Limit 4:** CO 8.6000 G/BHP-H

**RBLC ID: WV-0023**

**Corporate/Company:** LONGVIEW POWER, LLC

**Facility Name:** MAIDSVILLE

**Process:** EMERGENCY DIESEL GENERATOR; 600 KW

GOOD COMBUSTION PRACTICES; LIMITED TO 500 HOURS OF  
OPERATION A YEAR

**Emission Limit 1:** NOx 5.300 G/BHP-H

**Emission Limit 2:** VOC 1.000 G/BHP-H

**RBLC ID: IA-0067**

**Corporate/Company:** MIDAMERICAN ENERGY COMPANY

**Facility Name:** MIDAMERICAN ENERGY COMPANY

**Process:** EMERGENCY GENERATOR 1,788 HP

GOOD COMBUSTION PRACTICES

**Emission Limit 1:** PM./PM10 0.1400 LB/MMBTU

**Emission Limit 2:** NOx 1.710 LB/MMBTU

**Emission Limit 3:** VOC 0.090 LB/MMBTU

**Emission Limit 4:** CO 0.850 LB/MMBTU

**RBLC ID: OK-0091**

**Corporate/Company:** CARDINAL FG CO.

**Facility Name:** CARDINAL FG CO./ CARDINAL GLASS PLANT

**Process:** IC ENGINES, EMERGENCY GENERATORS (2) 2000 KW

ENGINE DESIGN AND LIMIT ON HOURS OF OPERATION (<500 H/YR)

**Emission Limit 1:** PM/PM10 0.0444 LB/MMBTU

**Emission Limit 2:** NOx 2.035 LB/MMBTU

**Emission Limit 3:** VOC LISTED IN LB/HR

**Emission Limit 4:** CO 0.2020 LB/MMBTU

**Firewater Pump Engine**

**NO<sub>x</sub>/PM/PM<sub>10</sub>/CO/VOC**

The RBL Clearinghouse lists eight BACT determinations for emergency diesel fire-water pumps or generators rated less than 500 HP. Control technologies include limiting the hours of operation, combustion control, the use of low sulfur oil, and injection timing retardation. NO<sub>x</sub> and CO emission limits for the Forsyth Energy Plant in Winston Salem, North Carolina are the most stringent at 7.7g/BHP-H (0.017 lb/BHP-H) and 2.05 g/BHP-H (0.0045 lb/BHP-H), respectively.

**BACT DETERMINATIONS FOR “SMALL EMERGENCY INTERNAL COMBUSTION ENGINES < 500 HP” 17.210**

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RBLC ID: OH-0275

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Corporate/Company: CINERGY

Facility Name: PSI ENERGY-MADISON STATION

Process: EMERGENCY DIESEL FIRE PUMP 1.60 MMBTU/H

**NO BACT LISTED**

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RBLC ID: NC-0101

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Corporate/Company: FORSYTH ENERGY PROJECTS, LLC

Facility Name: FORSYTH ENERGY PLANT

Process: IC ENGINES: EMERGENCY FIREWATER PUMP AND GENERATOR, EACH 11.40 MBTU/H

**NO<sub>x</sub> 7.7 g/BHP-H, CO 2.05 g/BHP-H, ASSUME 48% EFFICIENCY**

**LIMITED TO 500 HR/YR**

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RBLC ID: OH-0254

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Corporate/Company: DUKE ENERGY NORTH AMERICA

Facility Name: DUKE ENERGY WASHINGTON COUNTY LLC

Process: EMERGENCY DIESEL FIRE PUMP ENGINE 400 HP

**LOW SULFUR FUEL, COMBUSTION CONTROL**

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RBLC ID: MO-0067

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Corporate/Company: AQUILA, INC.

Facility Name: SOUTH HARPER PEAKING FACILITY

Process: IC ENGINE, EMERGENCY DIESEL FIRE PUMP 0.47 MMBTU/HR

**IGNITION TIMING RETARD (ITR) NO EMISSION LIMIT**

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RBLC ID: MT-0022

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Corporate/Company: BULL MOUNTAIN DEV. COMPANY

Facility Name: BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER  
PROJECT

Process: IC ENGINE, EMERGENCY GENERATOR 15.3 MMBTU/HR

**LIMITED TO 200 HRS/YR**

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RBLC ID: WA-0291

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Corporate/Company: WALLULA GENERATION, LLC

Facility Name: WALLULA POWER PLANT

Process: IC GENERATOR, EMERGENCY DIESEL

**LIMITED TO 200 HRS/YR**

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RBLC ID: OK-0110 AND OK-0111

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Corporate/Company: DALITALIA LLC

Facility Name: MUSKOGEE PORCELAIN FLOOR TILE PLT

Process: EMERGENCY GENERATORS

CO 0.0067 LB/HP-H; VOC 0.0025 LB/HP-H; PM<sub>10</sub> 0.0022 LB/HP-H

**GOOD COMBUSTION**

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**Natural Gas-Fired Heater**

**NO<sub>x</sub>/PM/PM<sub>10</sub>/CO/VOC**

A search of the RBL Clearinghouse shows four BACT determinations relevant to the proposed 4.0 million BTU/hr natural gas-fired heater. For NO<sub>x</sub>, BACT includes good combustion practices and low NO<sub>x</sub> burners. The lowest BACT limit is 0.10 lb NO<sub>x</sub>/MMBTU. For PM/PM<sub>10</sub>, CO, and VOC, BACT is good combustion practices. The most restrictive BACT limits are 0.0076 lb PM/PM<sub>10</sub> /MMBTU, 0.030 lb CO/MMBTU, and 0.0055 lb VOC/MMBTU.

**BACT DETERMINATIONS FOR “MISCELLANEOUS HEATERS” 19.600**

**RBLC ID: NV-0035**

**Corporate/Company:** SIERRA PACIFIC POWER COMPANY      **Primary Fuel:** NATURAL GAS  
**Facility Name:** TRACY SUBSTATION EXPANSION PROJECT      **Throughput:** 4.00 MMBTU/H  
**Process:** FUEL PREHEATER #2      **Process Code:** 19.600

**Pollutant Information - List of Pollutants**

Pollutant	Primary Emission Limit	Basis	Verified
Particulate Matter < 10 μ (PM10)	0.0200 LB/MMBTU	BACT-PSD	UNKNOWN
Nitrogen Oxides (NO <sub>x</sub> )	0.1400 LB/MMBTU	BACT-PSD	UNKNOWN
Carbon Monoxide	0.0300 LB/MMBTU	BACT-PSD	NO
Volatile Organic Compounds (VOC)	0.0800 LB/MMBTU	BACT-PSD	UNKNO

**No emission limits are specified under BACT**

**Corporate/Company:** AQUILA, INC.      **Primary Fuel:** NATURAL GAS  
**Facility Name:** SOUTH HARPER PEAKING FACILITY      **Throughput:** 9.80 mmBtu/h  
**Process:** FUEL GAS HEATER      **Process Code:** 19.600  
**BACT: LOW NOX BURNER**

**RBLC ID: AR-0077**

**Corporate/Company:** STEELCORR, INC.      **Primary Fuel:** NATURAL GAS  
**Facility Name:** BLUEWATER PROJECT      **Throughput:** 11.00 MMBTU/H  
**Process:** FURNACES, HEATERS, & DRYERS      **Process Code:** 19.600

**BACT: NATURAL GAS COMBUSTION ONLY**

Pollutant	Primary Emission Limit	Basis	Verified
Particulate Matter < 10 μ (PM10)	0.0076 LB/MMBTU	BACT-PSD	
Sulfur Dioxide (SO <sub>2</sub> )	0.0006 LB/MMBTU	BACT-PSD	
Volatile Organic Compounds (VOC)	0.0055 LB/MMBTU	BACT-PSD	
Carbon Monoxide	0.8400 LB/MMBTU	BACT-PSD	
Nitrogen Oxides (NO <sub>x</sub> )	0.1000 LB/MMBTU	BACT-PSD	

**RBLC ID: KY-0094**

**Corporate/Company:** NORTH AMERICAN STAINLESS  
**Facility Name:** NORTH AMERICAN STAINLESS  
**Process:** HEATER, SALT BATH, EMISSION POINT 84

<b>Primary Fuel:</b>	<b>NATURAL GAS</b>	<b>Pollutant</b>	<b>Primary Emission Limit</b>	<b>Basis</b>	<b>Verified</b>
<b>Throughput:</b>	5.60 mmbtu/h	<u>Visible Emissions (VE)</u>	20 % OPACITY	BACT-PSD	UNKNOWN
<b>Process Code:</b>	19.600	<u>Particulate Matter (PM)</u>	0.0417 LB/H	BACT-PSD	UNKNOWN
TWO NATURAL-GAS DRYERS HAVE COMBINED MAXIMUM BURNER CAPACITY OF 5.6 MMBTU/HR, EQUIPPED WITH LOW NOX BURNERS TO CONTROL NITROGEN OXIDE EMISSIONS.		<u>Nitrogen Oxides (NOx)</u>	0.5500 LB/H	BACT-PSD	UNKNOWN
		<u>Volatile Organic Compounds (VOC)</u>	0.0300 LB/H	BACT-PSD	UNKNOWN
		<u>Carbon Monoxide</u>	0.4600 LB/H	BACT-PSD	UNKNOWN

## **APPENDIX D**

### **Application**