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

PREVENTION OF SIGNIFICANT DETERIORATION PRECONSTRUCTION REVIEW AND PRELIMINARY DETERMINATION

FOR

UNIT 6
AT
DUKE ENERGY CAROLINAS LLC
CLIFFSIDE STEAM STATION
CLIFFSIDE, RUTHERFORD COUNTY
NORTH CAROLINA

THIS REVIEW WAS PERFORMED BY THE
AIR PERMITS SECTION
IN ACCORDANCE WITH 15A NCAC 2D .0530 - NCDAQ REGULATION
FOR
PREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY

August 14, 2007

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SECTION 1.0

INTRODUCTION

Duke Energy Carolinas LLC ("Duke") has submitted to the North Carolina Division of Air Quality (NCDAQ) a Prevention of Significant Deterioration (PSD) permit application (8100028.05B) proposing to expand the electric generation capacity of the Cliffside Steam Station located in Rutherford and Cleveland Counties.[1] The Cliffside facility operates under the current air permit 04044T27, which includes five coal-fired boilers, Units 1-5.[2] This expansion project includes installation of one, new, supercritical[3] pulverized coal-fired 800 MW boiler, and the retirement of existing Units 1-4. The new boiler (Unit 6) would be fired primarily with bituminous coal, or a blend of bituminous and sub-bituminous coals.

The North Carolina Utilities Commission (NCUC) is responsible for evaluating the need for and granting final approval of the construction of emission sources that are proposed by public utilities consistent with its obligations under N.C. Gen. Stat. §62-2. On February 28, 2007, NCUC issued a Notice of Decision approving the construction of one 800 MW coal-fired unit but found that Duke has not demonstrated the need for the second proposed unit.

Whereas the NCUC's role is to evaluate the need for these emissions sources, NCDAQ's role is to review the proposed emissions sources for compliance with all applicable State and Federal requirements. This document presents the results of NCDAQ's preconstruction review of Duke's application to build these emissions sources and, based on the information submitted thus far, offers a preliminary determination of the proposed project's compliance with existing regulations. In addition, an attached draft permit for these emission sources is set out for public comment. The purpose of the public comment period is to develop a complete record, taking into account all available information, so that NCDAQ can make a fully informed determination of whether this application in fact meets all legal and regulatory requirements.

The proposed project is a major stationary source,[4] classified under the category of "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input." Therefore, the facility is subject to review and processing under the North Carolina Administrative Code, Title 15A, Subchapter 2D, Section .0530 "Prevention of Significant Deterioration" (PSD). The plant must also comply with all other specific NCDAQ air pollution regulations where applicable (see Section 4.4).[5]

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[1] This application was deemed complete for administrative purposes on December 21, 2005, and complete for technical review pursuant to 40 CFR 51.166 (q)(1) and 15A NCAC 2D .0530(o) on July 6, 2007.

[2] A permit was issued on December 15, 2006, to add a flue gas desulfurization scrubber on Unit 5.

[3] Supercritical operation (greater than 3,208 psia steam pressure) allows the steam generation cycle to operate at an efficiency up to 10 percent greater than traditional sub-critical pressure units[0].

[4] As per 40 CFR 51.166(b)(1)(i)(a),

[5] Pursuant to the Federal Register notice on February 23, 1982, North Carolina 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 and process the PSD permit application for the proposed project. NC's State Implementation Plan (SIP) - approved PSD regulations have been codified in 15A NCAC 2D .0530.

The law requires review of all facilities, like this one, that emit or have the potential to emit 100 tons per year or more of particulate matter less than 10 micros in size (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC). Duke is proposing to net-out of PSD for SO_2 and NO_x; therefore emissions of these pollutants are not subject to PSD review (see Section 4.1) due to the retirement of Units 1-4 and the addition of a scrubber on Unit 5.

Based on the controlled emission rates of regulated air pollutants, the project is subject to PSD review for the discharge of CO, PM_{10}, VOCs, sulfuric acid mist (H_2SO_4) and lead (Pb).

As a key component of its preconstruction review for an emissions source of this size, NCDAQ is required by federal law to determine that Duke has selected the Best Available Control Technology (BACT) for key pollutants. Some parties have argued that Duke should include integrated gasification combined cycle (IGCC) as part of its BACT analysis. As a threshold matter, the Environmental Protection Agency (EPA) and NCDAQ have not required a BACT analysis to include review of technologies that fundamentally change the nature of the project and thus "redefine the source" proposed by the applicant. There is a lack of consensus among states on the question of whether the application of IGCC to a pulverized coal-fired power plant would redefine the source.[6] In addition, while IGCC technology holds great promise, NCDAQ finds that there is significant uncertainty with regard to the availability and applicability of this technology for base-load electric power generation at an 800-MW unit. As a result, NCDAQ has not required Duke to include IGCC in its BACT analysis for this application at this time. A discussion of this issue is presented in greater detail in Appendix F of this preliminary determination.

In accordance with PSD requirements, Duke has conducted a BACT analysis, source impact analysis, additional impacts (soils, vegetation, visibility) analysis, and Class I area analysis. To reduce emissions to BACT levels, Duke proposes to equip the new boiler with low-NO_x burners with overfire air and selective catalytic reduction (SCR) for control of NO_x emissions; spray dry absorbers followed by fabric filters (baghouse) for control of particulates/PM_{10}, sulfuric acid and lead; and a wet flue gas desulfurization (FGD) scrubber system for control of SO_2 and acid gases.

Coal supplies of varying heat value, sulfur content, ash content and other aspects of quality exist in different parts of the United States. In general, bituminous coal found east of the Mississippi River in Central Appalachia, Northern Appalachia and the Illinois Basin has high heat value, low to high sulfur content, and varying degrees of ash, moisture and other constituents. Western sub-bituminous coal, as found in the Powder River Basin (PRB) in the Great Plains, in general, has lower heat value, very low sulfur content, high moisture and varying degrees of other constituents. Duke has evaluated the available coals to fuel the new Cliffside boiler and chosen to burn eastern bituminous coal or a blend of eastern bituminous and sub-bituminous coals rather than burn only western sub-bituminous coal because the delivery and reliability is greater, the resulting emissions are comparable, and the costs of PRB coal and its transportation are significantly higher on an equivalent heating value basis.

[6] Most state air quality agencies have decided that IGCC, as applied to recent proposals for coal-fired units, would redefine the source. Two states have reached a different conclusion and required consideration of IGCC in a BACT analysis for a coal-fire power plant. However, no state air quality program has determined that IGCC is BACT for a coal-fired electric generating unit of any size.

The Cliffside Steam Station is relatively near sources of eastern bituminous coal. Duke states that it has reviewed various types of coal-fueled technology for electrical generation at Cliffside Unit 6, including: pulverized coal technology; circulating fluidized bed (CFB) technology; and IGCC technology.

In addition to the new coal-fired boiler, the project includes installation of an auxiliary boiler, cooling tower, emergency diesel-fired generator, emergency firewater pump, and new coal and ash material handling equipment, lime handling, and haul road fugitive sources.

Duke expects construction to begin soon after the air permit is issued, with operation of the unit projected to begin as early as 2011. Upon completion of the project, the facility (including existing Unit 5) will have a generating capacity of 1,360 MW.

1.1 Preliminary Determination

Duke's PSD application has been reviewed by the NCDAQ, Permitting Section staff, to determine compliance with the requirements of all NCDAQ air pollution regulations. The review was performed for the following:

- PSD including determination of BACT with consideration of non-PSD regulated toxic pollutants, source impact analysis, additional impact analysis on soils, vegetation and visibility, and Class I analysis.

- Compliance with the North Carolina Air Quality Rules at 15A NCAC 2D and 2Q.

The NCDAQ, Permitting Section staff has conducted a preconstruction review of the application based on the information submitted and made a preliminary determination that it complies with the applicable North Carolina air quality regulations including the PSD requirements. Therefore, the NCDAQ is placing a draft air permit for the modification described in Section 1 above, with specific permit conditions and emission limits, in the record for public comment. The purpose of the public comment period is to develop a complete record, taking into account all available information, so that NCDAQ can make a fully informed determination of whether this application in fact meets all legal and regulatory requirements. A preliminary determination of compliance under the PSD requirements was contingent upon the following findings:

- For each emission unit that will contribute to an increase in emissions of any pollutant above the significance threshold, a demonstration that Best Available Control Technology (BACT) is applied.

- A demonstration that National Ambient Air Quality Standards (NAAQS), and PSD Class II and Class I increments will not be violated as a result of emissions from the proposed project.

- A demonstration that emissions from the proposed project will neither cause adverse impacts to soils and vegetation nor cause degradation of visibility, and that economic growth associated with the project will not cause a significant increase in regional air pollutant levels.

- A demonstration that air emissions resulting from the proposed project will not adversely impact any PSD Class I area.

The remainder of this report contains a review by NCDAQ of the demonstration and analyses presented by Duke. Sections 2 and 3 of this report present a general description of the proposed project and a description of the site location. Section 4 presents a regulatory analysis of the North Carolina and Federal air quality regulations that apply to the project construction and operation. Section 5 contains the BACT analysis and Section 6 presents the results of the air quality analysis. The draft air permit is contained in Appendix A.

In addition to the regulatory analysis, 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. It is critical that NCDAQ have all relevant information before acting on this application. Specific public notice requirements and a 30-day public comment period are required before the NCDAQ can take final action on this application. Appendix B contains a copy of the public notice.

SECTION 2.0

GENERAL DESCRIPTION

2.1 Process Description

2.1.1 Existing Operations

Duke Energy's Cliffside Steam Station is an electric utility facility with emission sources consisting of five coal/No. 2 fuel oil-fired electric utility boilers, two No. 2 fuel oil/propane-fired auxiliary boilers, one flyash transfer and storage system consisting of one flyash vacuum handling system and one flyash storage silo, truck load out and blow off system, one flyash transfer and storage system consisting of one flyash vacuum handling system and one flyash storage silo, one limestone storage silo, and Unit 5 FGD system support equipment including: coal handling facilities, limestone and gypsum handling facilities, on-site landfill for disposal of ash and gypsum, and an emergency water pump for protection of the FGD system.

2.1.2 Proposed Modifications

Coal-fired Boiler

The project includes installation of one new supercritical pulverized coal-fired 800 MW boiler with design heat input of 7,850 mmBtu/hr. The boiler will be fired with bituminous coal, or a blend of bituminous and sub-bituminous coals, including Northern Appalachian eastern bituminous and Powder River Basin coals. The advantage of a supercritical design is that the high pressure and temperature steam cycle results in higher overall efficiency, lower emissions, and reduced fuel consumption.

Auxiliary Boiler

One No. 2 fuel oil/propane-fired 190 mmBtu/hr auxiliary boiler will be used to supply steam for start-up when the main boilers are not in operation.

Cooling Tower

A multi-cell mechanical induced draft cooling tower with a total recirculating water flow rate of 393,414 gallons per minute will be added for cooling the water from the shell-and-tube condenser of the steam turbine.

Emergency Generator

One No. 2 fuel oil-fired emergency generator rated at 2,350 hp will provide emergency power and will be limited to operating less than 100 hours per year.

Firewater Pump

One No. 2 fuel oil-fired emergency firewater pump rated at 430 hp will provide on-site fire fighting capability. This source will operate less than 100 hours per year.

Coal Handling

The following new Unit 6 coal handling equipment will be included (this system is fed through extension of the Unit 5 railcar coal unloading station)**:**

- U6 Coal Reclaim Hoppers (ID No. ES-C19)

Unit 6 Boiler House Coal Handling Point Source

- Coal Reclaim Conveyor RC11 to U6 Boiler Building (ID No. ES-C27)
- Coal Reclaim Conveyor RC12 to U6 Boiler Building (ID No. ES-C28)
- Unit 6 Tripper Conveyor TR2 (ID No. ES-C29)
- Unit 6 Tripper Conveyor TR3 (ID No. ES-C30)

- Coal Reclaim Feeders for Unit 6 (ID Nos. ES-VF1 thru ES-VF8)

Ash Handling

The following new Unit 6 ash handling equipment will be included:

- Wet Bottom Ash Transfer and Pickup (ID No. ES-A1)

Ash Handling Point Sources - Unit 6

- Two Dry Fly Ash Pickups at Boiler Economizer (ID No. ES-A3 and ES-A8)
- Dry Fly Ash Pickup at Bagfilter (ID No. ES-A9)
- Dry Fly Ash Silo (ID No. ES-A6)
- Dry Fly Ash Truck Loading (ID No. ES-A7)

- Dry Fly Ash Discharge to Truck (ID No. ES-A12)

Lime Handling

The following new Unit 6 lime handling equipment will be included to furnish lime to the operation of the spray dry absorbers:

- Lime Silo for SDA (ID No. ES-LSSDA)

Miscellaneous Source

The following other new Unit 6 fugitive emission source will be included:

- Facility haul roads (ID No. FVehicle)

2.2 Air Pollution Control Systems

The BACT analysis has concluded that for the coal-fired boiler, BACT will require the use of spray dry absorbers followed by fabric filters (baghouse) for PM_{10}, sulfuric acid and lead. In addition, the boilers will be equipped with low NO_x burners with overfire air, and state-of-the-art selective catalytic reduction (SCR) for NO_x control and a FGD scrubber for SO_2 control to meet emission requirements other than BACT. BACT for CO and VOCs emissions from the boiler has been determined to be good combustion control. For the auxiliary boiler, the BACT analysis has determined that NO_x and PM_{10} emissions will be controlled by burning only 0.05 percent low-sulfur No. 2 distillate fuel oil, low-NO_x burners, exhaust gas recirculation and by limiting operation to an annual capacity factor of no more than 10 percent. In addition, the auxiliary boiler will be equipped with low NO_x burners with overfire air for NO_x control to meet emission requirements other than BACT. BACT for the cooling towers will require state-of-the-art drift eliminators for particulate/PM_{10} emissions. For the emergency generator and firewater pump, the BACT analysis has determined that emissions will be controlled by burning only 0.05 percent low-sulfur No. 2 distillate fuel oil and limiting operation to no more than 100 hours per year. BACT for materials handling operations will require compliance with the new NSPS applicable to coal preparation operations and the use of partially enclosed conveyors, dust suppression and dust collection (e.g. fabric filters). A summary of the proposed BACT emission limits for the main boilers is presented in Table 5-1.

2.3 Emissions

This project is subject to PSD review for the discharge of CO, PM_{10}, VOCs, sulfuric acid mist (H_2SO_4) and lead (Pb). Duke is proposing to net out of PSD for NO_x and SO_2. A detailed emission analysis and summary for actual emissions increases and NO_x and SO_2 netting due to the proposed project are included in Section 4.1.

SECTION 3.0

REGIONAL DESCRIPTION

3.1 Area Classification

The facility is located on the southern bank of the Broad River, along the Rutherford County border near Cliffside, NC. The latitude and longitude of the facility are 35^o 12' 55" north and 81^o 45' 46" west, respectively. The base elevation of the site is approximately 775 feet above mean sea level. The Permittee has noted that the 3-km region surrounding the site is primarily rural, comprising the town of Cliffside, widely scattered businesses and residences, and forest and agricultural land.

Air quality with respect to the NAAQS in Rutherford County is classified as follows:

Pollutant	Attainment Status
PM_{10}	Attainment
$PM_{2.5}$	Attainment
Sulfur Dioxide	Attainment
Nitrogen Dioxide	Attainment
Carbon Monoxide	Attainment
Ozone	Attainment

Rutherford County is considered a Class II Area with ambient air increments for PM_{10}, SO_2, and NO_x.

The nearest Class I Area from this facility is Linville Gorge National Wilderness Area, which is located north and approximately 80 kilometers from the facility. Other Class I areas are shown in Section 6.

SECTION 4.0

REGULATORY ANALYSIS

The following discussion pertains to the regulatory requirements that must be met for the proposed modification to the Cliffside Steam Station. These requirements include both PSD regulations and other State air quality regulations.

4.1 Federal PSD Applicability and Required Analysis

Congress first established the New Source Review (NSR) program as part of the 1977 Clean Air Act Amendments and modified the program in the 1990 Amendments. The NSR program requires preconstruction review prior to obtaining a permit. The basic goal of NSR is to ensure that the air quality in clean (i.e. attainment) areas does not significantly deteriorate while maintaining a margin for future industrial growth. The NSR regulations focus on industrial facilities, both new and modified, that create large increases in the emission of certain pollutants. Prevention of Significant Deterioration (PSD) permits are a type of NSR permitting requirement for new major sources or sources making a major modification in an attainment area.

Pursuant to the Federal Register notice on February 23, 1982, North Carolina (NC) has full authority from the EPA to implement the PSD regulations in the State effective May 25, 1982. 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. The Code of Federal Regulations (CFR) in 15A NCAC 2D .0530 are incorporated by reference unless a specific reference states otherwise. The version of the CFR incorporated in 15A NCAC 2D .0530 is that as of November 7, 2003, except those provisions noticed as stayed in 69 FR 40274, and does not include any subsequent amendments or editions to the referenced material. The PSD regulations applicable to this project are the regulations in 15A NCAC 2D .0530 in effect as of the final permit issuance date. The latest revisions to 15A NCAC 2D .0530 became effective on July 28, 2006.

Under PSD requirements, all major new or modified stationary sources of air pollutants as defined in Section 169 of the Federal Clean Air Act (CAA) must be reviewed and permitted prior to construction by EPA or permitting authority, as applicable, in accordance with Section 165 of CAA. A "major stationary source" is defined as any one of 28 named source categories, which emits or has a potential to emit (PTE) 100 tons per year of any regulated pollutant, or any other stationary source, which emits or has the potential to emit 250 tons per year of any PSD regulated pollutant.

The Cliffside facility is an existing PSD major stationary source in an attainment area. It has been classified as one of the 28 named source categories under the category of "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input." It emits or has the potential to emit 100 tons per year of the following regulated pollutants: $PM_{10,}$ $PM_{2.5,}$ SO_2, NO_x, CO, and VOCs.

Note, even though $PM_{2.5}$ is a regulated NSR pollutant and there is a National Ambient Air Quality Standard (NAAQS) for $PM_{2.5}$, which became effective on September 16, 1997; as discussed in the Memorandum from John S. Seitz, Director Office of Air Quality Planning and Standards, to Regional Air Directors, *Interim Implementation of New Source Review for PM2.5* (Oct. 23, 1997); until EPA promulgates the $PM_{2.5}$ major NSR regulations, States should use PM_{10} as a surrogate for $PM_{2.5}$. This guidance was re-affirmed in the "Page" memo (http://www.epa.gov/nsr/documents/nsrmemo.pdf). On March 29, 2007, EPA issued a rule, known as the Clean Air Fine Particle Implementation Rule, defining requirements for State plans to clean the air in areas of nonattainment for $PM_{2.5}$ fine particle pollution. However, this rule did not include the NSR requirements for $PM_{2.5.}$ These requirements are expected to be addressed in separate rulemaking later in 2007. Therefore, at this time compliance for PM_{10} under the NSR regulations satisfies compliance for $PM_{2.5}$. Also, NCDAQ does not consider "PM" to be a regulated NSR pollutant and only uses PM as a surrogate for PM_{10}. Therefore, while PM is used to determine PSD applicability (Table 4-4), it is not thereafter considered in the BACT analysis.

For existing major stationary sources, there are several steps to determine whether the modification is a *major modification* and therefore subject to PSD preconstruction review. The first step is to determine whether there is a physical change or change in the method of operation. Second, there must be an emissions increase. And third, the emissions increase must be equal to or greater than certain "significance levels" as listed in 40 CFR 51.166(b)(23)(i) for the regulated pollutants.

Because the Cliffside modification involves a physical change and a change in the method of operation at a major stationary source which results in emission increases for regulated pollutants in the amounts equal or greater than the significance levels, the project is subject to PSD review and must meet certain requirements. The emission increases as a result of this modification are compared to the significance levels to determine which pollutants must undergo PSD review.

Facilities classified as major for PSD and applying for a significant modification are subject to all the requirements as defined in 40 CFR 51.166. These requirements include:

- a BACT determination, including an evaluation of unregulated pollutants such as toxic air pollutants,
- an Air Quality Impact Analysis including monitoring and air modeling to determine the extent and significance of any potential air quality impact, and
- an Additional Impacts Analysis including effects on soils, vegetation, and visibility.

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

> *An emissions limitation... based on the maximum degree of reduction for each pollutant... which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.*

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

Duke is netting out of NO_x and SO_2 by retiring Units 1-4 and adding a FGD scrubber on Unit 5; therefore emissions of NO_x and SO_2 are not subject to PSD review since there will not be a significant net emissions increase in these pollutants as allowed by 40 CFR 51.166(b)(3).

Under the PSD regulations, there is a requirement in 51.166(b)(3)(vi)(*c*) that, for a contemporaneous decrease (to be used for netting): "A decrease in actual emissions is creditable only to the extent that: ... (c) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change."

To address this issue, Duke demonstrated, through an additional modeling exercise (not pursuant to BACT), that the new facility will not show an increase in ambient impacts on the public as a result of netting for NO_x and SO_2. These modeling scenarios compare the ambient impacts for the future facility -- that is, with the new Unit 6 and Unit 5 modeled at their maximum allowable emission rates -- to the existing arrangement. A comparison of the future plants' modeled SO_2 impacts (ref: Updated Class II Modeling dated June 11, 2007) to the modeling results submitted as a part of the Cliffside Units 1-4 Stack Height Extension Project (see Table 4 in Section 8 of that report or e-mail to Ed Martin from Jeffrey Connors dated December 1, 2006, attached) shows the SO_2 emissions from the new generating units as compared to the retired Units 1-4 and the GEP stack height that will be used for Units 5 and 6 results in a much lower overall impact on the ambient air after completion of the proposed project. Similar results were shown for the NO_x analysis (ref: Updated Class II Modeling dated June 11, 2007, which contains both the new and existing arrangement results). Results of this modeling are shown in Section 6.1.

Even though Duke is netting out of SO_2 -- and therefore PSD review is not required for this pollutant -- the level of control for SO_2 pursuant to Senate Bill 1587 (as discussed in Section 4) requires essentially BACT-like controls for SO_2 since it requires Duke to install advanced control technology (FGD scrubber) designed to remove 99% of SO_2 and that Duke operate the advanced control technology any time electricity is being produced other than during startup of the unit, and requires SO_2 emissions to be below 0.15 lb/mmBtu on a rolling 30-day average.

As a regulated hazardous air pollutant (HAP), mercury (Hg) and beryllium (Be) are not regulated pollutants under PSD. EPA's Office of General Council (OGC) has stated that even though Hg is regulated under a Section 111 standard, BACT is not required for Hg from power plants, since requiring BACT for Hg would be inconsistent with Section 112(b)(6)'s prohibition of applying PSD to pollutants listed under Section 112.

Duke proposed netting out of hydrogen fluoride (HF). However, HF is not regulated as fluoride under PSD, since any section 112 listed HAP is not considered a regulated pollutant for NSR purposes per the definition in 51.166(b)(40). The units will only emit HF, not fluoride. HF is a 112 pollutant, fluoride is not. Therefore, netting of hydrogen fluoride is not applicable to this project.

4.1.1 Emissions Increases and SO_2 and NO_x Netting Analysis

Emissions from the new boilers are shown in Table 4-1 and total potential emissions and net emissions increases are summarized in Table 4-4, which includes project decreases due to retiring Units 1-4 (upon startup of the new boiler) from Table 4-2 and contemporaneous increases and decreases for the addition of a FGD scrubber on Unit 5 from Table 4-3. Baseline actual emissions and the resulting contemporaneous emission increases for the new Unit 5 FGD scrubber addition are shown in Table 4-3. No emission credits are taken and baseline emissions are assumed to be zero. Therefore, the creditable contemporaneous emission increases in actual emissions are equal to the potential emission increases.

As shown in Table 4-4, there is a *significant net emissions increase* for CO, PM_{10}, VOCs, sulfuric acid mist (H_2SO_4) and lead (Pb). Duke is proposing to net out of PSD for NO_x and SO_2 by using the reductions in these pollutants from retiring Units 1-4 and the addition a FGD scrubber on Unit 5, and by taking a federally-enforceable PSD avoidance limit on future facility-wide NO_x and SO_2 emissions to keep those emissions from increasing beyond the baseline facility-wide values. Therefore, as allowed by 40 CFR 51.166(b)(3), emissions of NO_x and SO_2 are not subject to PSD review since there will not be a significant net emissions increase as discussed below in Section 4.1.1.2. The net emissions increase in Table 4-4 includes the reductions in NO_x and SO_2 from the baseline as a result of the PSD avoidance limit. Based on the controlled emission rates of regulated air pollutants, as shown in Table 4-4, the proposed modification will produce significant emissions of, and is therefore subject to PSD review for CO, PM_{10}, VOCs, sulfuric acid mist (H_2SO_4) and lead (Pb). The detailed emission calculations for PSD applicability can be found in Duke's application. The Unit 5 scrubber addition was recently permitted on December 15, 2006.

The emission rates in this section are the emission rates used to show compliance with the NAAQS and PSD increments.

4.1.1.1 Emissions Increases

As stated above, a project is a *major modification* for a regulated pollutant under PSD regulations if emission increases are equal to or greater than the significance levels. At an existing PSD major stationary source, a project is a *major modification* for a regulated pollutant under PSD regulations if it causes two types of emissions increases – a *significant emissions increase* and a *significant net emissions increase*.

Significant Emissions Increase

As new sources, the modification must meet the actual-to-potential applicability test under 40 CFR 51.166(a)(7)(iv)(*d*) to determine whether there is a *significant emissions increase*. Under this test, a significant emissions increase occurs if the difference between the *potential to emit* (as defined in §51.166(b)(4)) following completion of the project and the *baseline actual emissions* exceeds the significance threshold for each PSD pollutant. Baseline actual emissions for a new unit are defined by §51.166(b)(47)(iii) as zero. Therefore, there is a significant emissions increase for all pollutants (as shown in Table 4-4), since the *potential to emit* is greater than the PSD significance thresholds shown at the bottom of the table.

Significant Net Emissions Increase
Next, it must be determined whether there is also a *significant net emissions increase* as defined by §51.166(b)(3). This requires consideration of any other creditable emissions increases and decreases in actual emissions at the source that are contemporaneous with the particular change. An increase or decrease in actual emissions is contemporaneous with the particular change if it occurs within a reasonable period of time before the increase from the particular change occurs. In North Carolina, the reasonable contemporaneous period of time is 7 years.

Contemporaneous emission increases and decreases for the modification result from the addition of the Unit 5 FGD scrubber. Baseline actual emissions are required in order to calculate these contemporaneous emission changes. *Baseline actual emissions* for calculating contemporaneous increases and decreases is defined in 15A NCAC 2D .0530(b)(1) as "…the average rate in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date the application is received by the Division…" Baseline emissions must also be representative of normal source operation. Only one consecutive 24-month period can be used to determine baseline emissions for each pollutant for all the emission sources being changed; however, a different consecutive 24-month period can be used for each pollutant.

4.1.1.2 Netting Analysis for SO_2 and NO_X

Emissions Increase for SO_2
Potential SO_2 emissions from the boiler, with a heat input of 7,850 mmBtu/hr, will be limited to 0.15 lb/mmBtu resulting in annual potential emissions of:

(0.15 lb/mmBtu) (7,850 mmBtu/hr) (8,760 hr/yr)/(2,000 lb/ton) = 5,157.5 tpy

SO_2 emissions from the ancillary equipment are 9.7 tpy. In addition, emission reductions due to retiring Units 1-4 could be included; however, Duke has elected not to include these reductions at this time. Even so, to establish these reductions for future use, baseline emissions must be determined. Baseline actual emissions and the resulting emission decreases for retiring the existing Units 1-4 are shown in Table 4-2. Duke has used actual emissions from EPA's Clean Air Markets data for the two-year period 2001 and 2002 for SO_2 and for the two-year period 2003 and 2004 for NO_X, and used DAQ inventory data for other pollutants. Future projected actual emissions for retiring these units will be zero. Therefore, the creditable emission decreases in actual emissions equal the baseline emissions. The two-year average SO_2 emissions reduction for retiring Units 1-4 in the amount of 5,459 tpy as shown in Table 4-6 is not included in the baseline (or the Unit 5 and 6 PSD limit) and will be held in reserve for future projects. Total SO_2 emissions increases for the modification are then:

Potential to Emit	=	Unit 6	+	Ancillary Sources	-	Retiring Units 1-4
	=	5,157.5 tpy	+	9.7 tpy	-	0 tpy
	=	5,167.2 tpy				

Since baseline actual emissions for a new unit are zero, there is a *significant emissions increase* of:

potential to emit – baseline actual emissions = 5,167.2 tpy – 0 tpy = 5,167.2 tpy

Net Emissions Increase for SO_2

As in the case of the other pollutants (above), to determine whether there is also a *significant net emissions increase* for SO_2, any other creditable emissions increases and decreases in actual SO_2 emissions at the source that are contemporaneous with the particular change must be considered. Contemporaneous SO_2 emission decreases result from the addition of the Unit 5 FGD scrubber. These reductions occur as a result of Duke's proposal to net out of PSD for SO_2 by taking a practically-enforceable PSD avoidance limit to keep future facility-wide SO_2 emissions from increasing beyond the baseline facility-wide values (plus 39.9 tpy). Actual facility-wide baseline SO_2 emissions (Units 1-4 and Unit 5) along with the resulting SO_2 PSD avoidance limit for the new arrangement (Units 5 and 6) are shown in Table 4-6. The PSD avoidance limit is established by subtracting the maximum allowable potential emissions for all facility-wide sources of SO_2 (ancillary sources), shown in Table 4-5, from the baseline emissions (plus 39.9 tpy). Since the maximum potential emissions for all facility-wide sources are assumed to be emitted, monitoring or recordkeeping is not required for any sources other than Units 5 and 6. Therefore, the PSD avoidance limit applies only to Units 5 and 6.

The total potential SO_2 emissions from the modification of 5,167.2 tpy, as shown in Table 4-4, may be offset in part by the contemporaneous SO_2 reductions as a result of the Unit 5 FGD scrubber modification and this is reflected in the Units 5 and 6 PSD avoidance condition which can vary as long as the limit is met. The PSD avoidance limit will ensure the facility will not have a significant increase in SO_2 so that Duke can therefore net out of SO_2. The practically-enforceable PSD combined Unit 5 and 6 SO_2 avoidance emissions limit (Section 2.2 C.1 of the permit) of 25,186 tpy (from Table 4-6) prevents a significant increase in SO_2 emissions, as a result of the modification, by capping future facility-wide SO_2 emissions at the baseline plus 39.9 tpy.

As discussed above (Section 4.1), the PSD regulations applicable to this project are the regulations in effect as of the final permit issuance date, and these latest revisions to 15A NCAC 2D .0530 became effective on July 28, 2006. This rule at 15A NCAC 2D .0530(b)(1)(A)(iv) states that for an electric utility steam generating unit, the baseline emission rate shall be adjusted downward to reflect any emissions reductions under General Statue 143-215.107D. This legislation, known as the "Clean Smokestacks Act," was passed into law by the General Assembly of North Carolina in 2001 to improve air quality in the State by imposing limits on SO_2 and NO_x emissions from Duke Energy and Progress Energy facilities. The reductions in emissions used by Duke in this application to net out of SO_2 were part of the reductions required under the Clean Smokestacks Act andwould have been disallowed under the current rule.

However, Senate Bill 1587[7], which was passed by the General Assembly and signed into law by the Governor on August 23, 2006, states that the provisions of 15A NCAC 2D .0530(b)(1)(A)(iv) do not apply to any application for an air quality permit that is submitted and determined to be administratively complete by the Department of Environment and Natural Resources on or before August 1, 2006. The application for this modification was administratively complete before August 1, 2006; and therefore, any reductions in SO_2 emissions required under the Clean Smokestacks Act may be included in the baseline emission rates.

Based on the above analysis, there will not be a significant *net emissions increase* as defined by §51.166(b)(3) for SO_2.

Emissions Increase for NO_x

Potential NO_x emissions from the Unit 6 boiler, with a heat input of 7,850 mmBtu/hr, will be limited by the Unit 5 and 6 (facility-wide) NO_x cap of 6,370 tpy to avoid the applicability of PSD. However, Duke has based their ability to net out of NO_x on an expected emission rate of 0.07 lb/mmBtu. Therefore, at this emission rate, annual NO_x emissions will be (as shown in Table 4-4):

(0.07 lb/mmBtu) (7,850 mmBtu/hr) (8,760 hr/yr)/(2,000 lb/ton) = 2,406.8 tpy

NO_x emissions from the ancillary equipment are 4.3 tpy. In addition, emission reductions due to retiring Units 1-4 must be included. The two-year average NO_X emissions reduction for retiring Units 1-4 is 958.4 tpy as shown in Table 4-7. Therefore, total NO_x emissions increases for the modification are then:

Potential to Emit	=	Unit 6	+	Ancillary Sources	-	Retiring Units 1-4
	=	2,406.8 tpy	+	4.3 tpy	-	958.4 tpy
	=	1,452.7 tpy				

Since baseline actual emissions for a new unit are zero, there is a *significant emissions increase* of:

potential to emit – baseline actual emissions = 1,452.7 tpy – 0 tpy = 1,452.7 tpy

Net Emissions Increase for NO_x

To determine whether there is also a *significant net emissions increase* for NO_x, any other creditable emissions increases and decreases in actual NO_x emissions at the source that are contemporaneous with the particular change must be considered.

[7] This requirement is interpreted to apply to Unit 6. This bill also required any permit issued pursuant to this bill to both: (1) Include a requirement that the permittee will install advanced control technology designed to remove ninety-nine percent (99%) of any pollutants at each electric generating unit to which 15A NCAC 2D .0530(b)(1)(A)(iv) would otherwise apply and that the permittee will operate the advanced control technology at any time that electricity is being produced by the electric generating unit other than during startup of the unit (this requirement is one of design only); and (2) State that the actual emissions of sulfur dioxide (SO2) shall be no greater than 0.15 pound per million British Thermal Units (BTUs) as measured on a rolling 30-day average.

Duke is proposing to net out of PSD for NO_x by taking a practically-enforceable PSD avoidance limit to keep future facility-wide NO_x emissions from increasing beyond the baseline facility-wide values (plus 39.9 tpy). Actual facility-wide baseline NO_x emissions (Units 1-4 and Unit 5) along with the resulting NO_x PSD avoidance limit for the new arrangement (Units 5 and 6) are shown in Table 4-7. The PSD avoidance limit is established by subtracting the maximum potential emissions for all facility-wide sources of NO_x (ancillary sources), shown in Table 4-5, from the baseline emissions (plus 39.9 tpy). Since the maximum potential emissions for all facility-wide sources are assumed to be emitted, monitoring or recordkeeping is not required for any sources other than Units 5 and 6. Therefore, the PSD avoidance limit applies only to Units 5 and 6 or to Unit 5 only.

The total potential NO_x emissions from the modification of 1,452.7 tpy, as shown in Table 4-4, may be offset in part by contemporaneous reductions in NO_x emissions on Unit 5. The PSD avoidance limit will ensure the facility will not have a significant increase in NO_x so that Duke can therefore net out of NO_x. The practically-enforceable PSD combined Unit 5 and 6 NO_x avoidance emissions limit (Section 2.2 C.1 of the permit) of 6,370 tpy (from Table 4-7) prevents a significant increase in NO_x emissions, as a result of the modification, by capping future facility-wide NO_X emissions at the baseline plus 39.9 tpy.

As stated above for SO_2, Senate Bill 1587 likewise allows the reductions in NO_x, required by the Clean Smokestacks Act, to be included in the baseline emission rates.

Based on the above analysis, there will not be a significant *net emissions increase* as defined by §51.166(b)(3) for NO_x.

Table 4-1
Emissions – Unit 6 Boiler

Pollutant	Proposed Emission Rate		
	lb/mmBtu	lb/hour[1]	tons/year[2]
SO_2	0.15	1,177.5	5,157.5
NO_x	0.07	549.5	2,406.8
PM	0.012	94.2	412.6
PM_{10} (filterable only)	0.012	94.2	412.6
PM_{10} (filterable + condensable)	0.018	141.3	618.9
CO	0.12	942	4,126.0
VOC	0.004	31.4	137.5
H_2SO_4	0.005	39.3	171.9
Lead	0.000022	0.17	0.75

1 lb/hour is based on heat input of 7,850 mmBtu/hr.
2 tons/year is based on heat input of 7,850 mmBtu/hr and 8,760 hours/year operation.

Table 4-2
Creditable Emissions Decreases for Retiring Units 1-4

Units 1-4	SO_2 (tpy)	NO_X (tpy)	PM (tpy)	PM_{10} (tpy)	CO (tpy)	VOC (tpy)	H_2SO_4 (tpy)	Lead (tpy)
Actual Emissions 2001[1]		1,196.8						
Actual Emissions 2002[1]		719.9						
Actual Emissions 2003[1]	6,794		450.1	400.7	80.3	9.7	42	0.1
Actual Emissions 2004[1]	4,124		247.2	220.9	48.7	5.9	25	0.1
2-Year Average Baseline Emissions	5,459	958.4	348.6	310.8	64.5	7.8	33.5	0.1
Future Projected Actual Emissions	0	0	0	0	0	0	0	0
Creditable Emissions Decreases	**5,459**	**958.4**	**348.6**	**310.8**	**64.5**	**7.8**	**33.5**	**0.1**

[1] From EPA's Clean Air Markets data at http://camddataandmaps.epa.gov/gdm/ for NO_X and SO_2 and from DAQ emissions inventories for other pollutants.

Table 4-3
Contemporaneous Creditable Emissions Increases for Addition of Unit 5 FGD

Unit 5	SO_2 (tpy)	NO_X (tpy)	PM (tpy)	PM_{10} (tpy)	CO (tpy)	VOC (tpy)	H_2SO_4 (tpy)	Lead (tpy)
Potential Emissions Increases [1]	0	0.3	21.9	6.6	0.2	0.3	0	0
Baseline Actual Emissions	0	0	0	0	0	0	0	0
Creditable Emissions Increases	**0**	**0.3**	**21.9**	**6.6**	**0.2**	**0.3**	**0**	**0**

[1] Emissions from Tab C of May 2007 Application Addendum.

Table 4-4
Emissions Summary for the Proposed Project

	SO_2 (tpy)	NO_X (tpy)	PM (tpy)	PM_{10} filt+cond (tpy)	CO (tpy)	VOC (tpy)	H_2SO_4 (tpy)	Lead (tpy)
Emission Increases/Decreases from Proposed Modification								
Main Boiler - Unit 6[1]	5,157.5	2,406.8	412.6[2]	618.9[3]	4,126.0	137.5	171.9	0.75
Ancillary Sources	9.7	4.3	9.2	2.2	3.8	1.6	0.1	0
Retiring Units 1-4[4]	reserved[5]	-958.4	-348.6	-310.8	-64.5	-7.8	-33.5	-0.1
Potential to Emit	5,167.2	1,452.7	73.2	310.3	4,065.3	131.3	138.5	0.65
Contemporaneous Emission Increases/Decreases from Unit 5 Scrubber Project								
Increases[6]	0	0.3	21.9	6.6	0.2	0.3	0	0
Decreases due to PSD Avoidance Limit[7]	-5,167.2+39.9	-1,453.0+39.9						
Total Modification Increases								
Net Emissions Increase	**39.9**	**39.9**	**95.1**	**316.9**	**4,065.5**	**131.6**	**138.5**	**0.65**
PSD Threshold	40	40	25	15	100	40	7	0.6
PSD Review Required?	**no**	**no**	**yes**	**yes**	**yes**	**yes**	**yes**	**yes**

1 From emission rates in Table 4-1.
2 Based on filterable PM emissions rate of 0.012 lb/mmBtu.
3 Based on filterable + condensable PM_{10} emissions rate of 0.018 lb/mmBtu.
4 From Table 4-2.
5 These reductions in the amount of 5,459 (see Table 4-6) are not included in this modification and are to be reserved for future projects.
6 From Table 4-3.
7 Reductions in SO_2 and NO_X emissions as a result of the PSD avoidance limits keep emissions below the PSD threshold. See Tables 4-6 and 4-7.

Table 4-5
Potential Emissions from Facility-Wide Ancillary Sources (all sources except Units 5 and 6)
(To Determine PSD Avoidance Limit)

Emission Source Description	ID No.	Operation (hrs)	NOx (tpy)	SO_2 (tpy)
Unit 5 Fire Water Pump	ES-FWP5	100	0.36	0.043
Unit 5 Quench Pump	ES-QP5	100	0.23	0.0004
Unit 5 Aux Boiler (71.5 mmBtu/hr)	ES-6(AuxB)	8760	43.84	720.3
Emergency Generator (1000 kw)	ES-12(EmGen)	100	1.49	0.242
Unit 6 Aux Boiler (190 mmBtu/hr)	ES-Aux6	876	8.32	4.3
Unit 6 Fire Water Pump	ES-FWP	100	0.63	0.0007
Unit 6 Emergency Generator	ES-EG1	100	0.53	0.0006
Total			**56**	**725**

Table 4-6
Future Allowable Facility-Wide SO_2 Emissions Cap
(PSD Avoidance Limit for Units 5 and 6)

			SO_2 Emissions (tpy)	
Baseline Emissions[1]	Units 1-4	Actual Emissions 2003	6,794	
		Actual Emissions 2004	4,124	
		2-Year Average	5,459 credits to be reserved for future	
	Unit 5	Actual Emissions 2003	28,183.1	
		Actual Emissions 2004	23,558.1	
		2-Year Average	25,870.6 →	25,870.6
PSD Significance Level				40
Future Allowable Facility-Wide SO_2 Emissions Cap				25,911
Potential SO_2 Emissions from Facility-Wide Ancillary Sources[2]				-725
PSD SO_2 Avoidance Limit for Units 5 and 6				**25,186**

1 From EPA's Clean Air Markets data at http://camddataandmaps.epa.gov/gdm/.
2 From Table 4-5.

Table 4-7
Future Allowable Facility-Wide NO_X Emissions Cap
(PSD Avoidance Limit for Units 5 and 6)

			NO_X Emissions (tpy)	
Baseline Emissions[1]	Units 1-4	Actual Emissions 2001	1,196.8	
		Actual Emissions 2002	719.9	
		2-Year Average	958.4 →	958.4
	Unit 5	Actual Emissions 2001	7,942.6	
		Actual Emissions 2002	2,912.9	
		2-Year Average	5,427.8 →	5,427.8
PSD Significance Level				40
Future Allowable Facility-Wide NO_X Emissions Cap				6,426.2
Potential NO_X Emissions from Facility-Wide Ancillary Sources[2]				-56
PSD NO_X Avoidance Limit for Units 5 and 6				**6,370**
PSD NO_X Avoidance Limit for Unit 5 only[3]				**2,465**

1 From EPA's Clean Air Markets data at http://camddataandmaps.epa.gov/gdm/.
2 From Table 4-5.
3 A PSD NO_X limit is needed for Unit 5 only, because NO_X modeling (see Section 6.2) to comply with the requirement to demonstrate the new arrangement will not result in a lower qualitative significance on public health and welfare than the old arrangement, was based on an emission rate of 2,465 tpy.

4.2 Federal NSPS Regulations

4.2.1 NSPS Subpart Da – Standards of Performance for Electric Utitily Steam Generating Units for Which Construction Commenced After September 18, 1978

Subpart Da applies to the new coal-fired boiler (ID No. ES-6) since it is an electric utility steam generating unit capable of burning more than 250 mmBtu/hr heat input of fossil fuel. The latest version of this rule became effective February 9, 2007.

Emission Limits
The following emission limits apply:

POLLUTANT	EMISSION LIMIT
particulate matter	0.015 lb/mmBtu heat input
opacity	20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity
sulfur dioxide	1.4 lb/MWh gross energy output (30-day rolling average), or 95% reduction (30-day rolling average)
nitrogen oxides (expressed as NO_2)	1.0 lb/MWh gross energy output (30-day rolling average)
mercury	0.020 lb/GWh gross energy output when burning only bituminous coal 0.066 lb/GWh gross energy output when burning only subbituminous coal 0.016 lb/GWh gross energy output when burning only coal refuse For blended coals, the weighted emission rate is computed based on all coal types using the procedures in 40 CFR 45a(a)(5) (12-month rolling average)

Compliance
After the initial performance test in Part II of the permit required under 40 CFR §60.8, compliance with the sulfur dioxide emission limitation or percentage reduction requirement under §60.43a and the nitrogen oxides emission limitations under §60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards. As long as the sulfur dioxide emission limitation of 1.4 lb/MWh gross energy output is met, the percentage reduction requirement is not applicable.

Continuous monitoring systems are required for measuring the opacity (unless the source installs a continuous particulate monitoring system (CEMS) to demonstrate compliance with the particulate emission limit as discussed below), sulfur dioxide, nitrogen oxides, and mercury.

Compliance with the PM emission limit is to be demonstrated by one of the three basic alternates in accordance with §60.48a(o) and (p) of Subpart Da: using a COMS, a fabric filter bag leak detection system, or a PM CEMS, as discussed below.

COMS

The source must conduct an initial stack performance test to demonstrate compliance with the PM limit and must conduct subsequent performance tests within 12 calendar months of the date of the prior performance test. A continuous opacity monitoring system (COMS) must be used to demonstrate compliance with the opacity limit.

The source must monitor the performance of each fabric filter (baghouse) to comply with the PM emission limit by using a COMS.unless the source elects to comply with the alternative below for a fabric filter bag leak detection system. During each stack performance test, the source must establish an opacity baseline level and evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level, the source must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level. Records must be kept of the opacity measurements, calculations performed, and any corrective actions taken. If the measured 24-hour average opacity remains at a level greater than the opacity baseline level after 7 days, then a new PM emission stack performance test must be conducted to establish a new opacity baseline value.

Fabric Filter Bag Leak Detection System

The source must conduct an initial stack performance test to demonstrate compliance with the PM limit and must conduct subsequent performance tests within 12 calendar months of the date of the prior performance test. A COMS must be used to demonstrate compliance with the opacity limit.

As an alternative to using COMS as discussed above, the source may elect to monitor the performance of a fabric filter (baghouse) to comply with the PM emission limit by using a bag leak detection system. The source must develop and submit to the DAQ for approval a site-specific monitoring plan for each bag leak detection system. The bag leak detection system must be operated and maintained according to the site-specific monitoring plan at all times. For each bag leak detection system, the source must initiate procedures to determine the cause of every alarm within 1 hour of the alarm and take corrective action(s) within 3 hours including:

(a) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in PM emissions;
(b) Sealing off defective bags or filter media;
(c) Replacing defective bags or filter media or otherwise repairing the control device;
(d) Sealing off a defective fabric filter compartment;

(e) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or
(f) Shutting down the process producing the PM emissions.

The owner or operator must maintain records of the system output and certain system parameters specified in the permit. If after any period composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then the source must conduct a new PM stack performance test.

PM CEMS

As an alternative to meeting the above two alternates, the source may elect to install, certify, maintain, and operate a CEMS measuring PM emissions and record the output of the system. Compliance with the PM emissions limit shall be determined based on a 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the CEMS outlet data using EPA Reference Method 19.

Particulate matter, opacity, nitrogen oxides and mercury standards apply at all times except during periods of startup, shutdown, or malfunction. Sulfur dioxide standards apply at all times except during periods of startup and shutdown.

4.2.2 NSPS Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Subpart Db applies to the auxiliary boiler (ID No. ES-Aux6) since it is a steam generating unit for which construction commences after June 19, 1984 and has a heat input capacity greater than 100 mmBtu/hr. The latest version of this rule became effective June 9, 2006.

Emission Limits

This boiler will be limited to an annual capacity factor not to exceed 10 percent and will only fire No. 2 fuel oil (except for propane during startup) with a nitrogen content of 0.30 weight percent or less and sulfur content of 0.30 weight percent or less. As such, there are no sulfur dioxide, nitrogen oxide, particulate or opacity emission limits.

Compliance

The facility must demonstrate the maximum heat input capacity by operating the boiler at maximum capacity for 24 hours in accordance with 40 CFR §60.46b(g). This demonstration of maximum heat input capacity is made during the initial performance test within 60 days after achieving the maximum production rate but not later than 180 days after initial start-up. The source must obtain and maintain at the facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b to demonstrate that the affected facility burns only very low sulfur oil under §60.42b. No other monitoring is required. Records must be maintained of the amounts of each fuel combusted during each day to calculate the annual capacity factor for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month in accordance with §60.49b(d).

4.2.3 NSPS Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII (promulgated on July 11, 2006) applies to several categories of compression ignition (CI) engines. The emergency source subject to this standard include one 2,350 hp emergency generator (ID No. ES-EG6) and one 430 hp emergency firewater pump (ID No. ES-FWP).

The emergency generator diesel engine has a displacement of less than 10 liters per cylinder and will be installed sometime between 2007 and 2011. The emergency generator provides power in emergency situations. This source must meet the requirements in §60.4202(a) of the standard. These standards are for emergency engines less than 3,000 hp but greater than 50 hp, and less than 10 liters per cylinder displacement. An emergency engine built for model year 2007 and later that is not a fire pump would be subject to emission limits of 40 CFR 89.112 and 40 CFR 89.113.

The emergency firewater pump engine has a displacement of less than 10 liters per cylinder and will be installed sometime between 2007 and 2011. This source must meet the requirements in §60.4205(c) of the standard.

Emission Limits

The following emission limits apply:

AFFECTED SOURCE	POLLUTANT	EMISSION LIMIT (g/hp-hr)
emergency generators (ID No. ES-EG6) [§60.4202(a)]	nitrogen oxides + VOCs	4.8
	carbon monoxide	2.6
	PM	0.15
emergency firewater pump (ID No. ES-FWP) [§60.4205(c)]	nitrogen oxides + VOCs	7.8 (2008 and earlier) 3.0 (2009 and later)
	carbon monoxide	2.6
	PM	0.15 (2008 and earlier) 0.15 (2009 and later)

The applicable smoke or opacity emission standards in §89.113 do not apply since the engines are constant speed engines.

Compliance

The engines must be operated and maintained according to the manufacturer's written instructions or procedures. Engines for 2007 or later must comply with the standard by assuring that the engine purchased is certified to meet the applicable emissions standards and must install and configure the engine according to the manufacturers specifications.

Beginning October 1, 2007, the engines must use diesel fuel with a sulfur content of less than 500 ppm as per 40 CFR 80.510(a). For operation after October 1, 2010, the engines must use diesel fuel with sulfur less than 15 ppm as per 40 CFR 80.510(b).

An emergency engine may be operated for maintenance and readiness checks for up to 100 hours per year in accordance with the NSPS requirements. Operation during an actual emergency is not subject to a limit on hours.

4.2.4 NSPS Subpart Y - Standards of Performance for Coal Preparation Plants

Subpart Y applies to affected facilities constructed, reconstructed or modified after October 24, 1974 in coal preparation plants, which process more than 200 tons per day. The affected facilities under this NSPS are thermal dryers, pneumatic coal-cleaning equipment, coal conveying and processing equipment (including crushers), coal storage systems, and coal transfer and loading systems.

The proposed coal unloading, handling, storage, and crushing facility has a capacity of 5,000 tons per hour. Because this facility will be constructed in 2006 or after and it has a capacity to process coal more than 200 tons per day, it is subject to the requirements of NSPS Subpart Y.

Subpart Y applies to the following affected emission sources:

- U6 Coal Reclaim Hoppers (ID No. ES-C19)

Unit 6 Boiler House Coal Handling Point Source

- Coal Reclaim Conveyor RC11 to U6 Boiler Building (ID No. ES-C27)
- Coal Reclaim Conveyor RC12 to U6 Boiler Building (ID No. ES-C28)
- Unit 6 Tripper Conveyor TR2 (ID No. ES-C29)
- Unit 6 Tripper Conveyor TR3 (ID No. ES-C30)

- Coal Reclaim Feeders for Unit 6 (ID Nos. ES-VF1 thru ES-VF8)

Emission Limits for PM

Opacity of emissions from the above affected emission units shall be less than 20 percent opacity.

Compliance

To assure compliance, the facility must perform inspections and maintenance as recommended by the manufacturer and, as a minimum, the inspection and maintenance requirement shall include a monthly visual inspection of the system ductwork and material collection unit for leaks, and an annual internal inspection of the bagfilter's structural integrity (for point sources).

4.2.5 NSPS Subpart OOO - Standards of Performance for Nonmetallic Mineral Processing Plants

Subpart OOO applies to each fixed nonmetallic mineral processing plant constructed, reconstructed or modified after August 1, 1983, with capacities exceeding 25 tons per hour. The affected facilities under the NSPS are each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station. Nonmetallic mineral means crushed and broken stone including limestone, and dolomite, among others.

The proposed limestone facility will have a capacity of 2,800 tons per hour and it will be constructed in or after 2006. Therefore, it is subject to Subpart OOO. Subpart OOO applies to the following affected emission source:

- Lime Silo for SDA (ID No. ES-LSSDA)

Emission Limits PM

Stack emissions of particulate matter from affected facility (ID No. ES-LS13-3) shall not exceed 0.05 g/dscm (0.022 gr/dscf) and 7 percent opacity. Fugitive emissions from affected facilities (ID Nos. ES-LSBM3 and ES-LS15) shall not be more than 10 percent opacity.

Compliance

To assure compliance, once a month the facility must observe the emission sources for any visible emissions above normal and perform inspections and maintenance as recommended by the manufacturer and, as a minimum, the inspection and maintenance requirement shall include a monthly visual inspection of the system ductwork and material collection unit for leaks, and an annual internal inspection of the bagfilter's structural integrity (for point sources).

4.3 Federal NESHAP Regulations - Maximum Achievable Control Technology

4.3.1 Part 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE)

Subpart ZZZZ applies to any RICE located at major source with a site-rating of 500 BHP or more. Any stationary RICE constructed after December 19, 2002 has been defined as "new stationary RICE".

The proposed emergency generator RICE's site-rating is 2,350 BHP. It is a "new stationary RICE," as its commencement of construction will be in 2006 or after, and finally, it will be located at a major source of HAP emissions (such as HCl, HF, etc.) It will be required to demonstrate compliance with the MACT upon startup. However, because this engine has been deemed as "emergency stationary RICE" as defined in §63.6675, the proposed engine will have to comply with only initial notification requirements in Subpart A, and the Permittee does not have to comply with requirements of Subpart ZZZZ or any other requirements in Subpart A. See §63.6590(b)(i).

4.4 State NCDAQ Air Pollution Regulations

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

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

Regulation	Affected Sources	Regulatory Requirements
2D .0503	coal-fired boiler aux boiler	PM emissions cannot exceed 0.10 lb/mmBtu
2D .0510	limestone handling	PM emission ambient air quality standards
2D .0515	cooling towers coal handling ash & gypsum handling	PM emission limit
2D .0516	aux boiler emergency engines	SO_2 emissions cannot exceed 2.3 lb/mmBtu
Senate Bill S1587	coal-fired boiler	SO_2 emissions cannot exceed 0.15 lb/mmBtu
2D .0519	coal-fired boiler	NOx emissions cannot exceed 1.8 lb/mmBtu (when burning coal) and 0.8 lb/mmBtu (when burning oil)
2D .0521	emergency engines ash & gypsum handling	Visible emissions cannot exceed 20 percent opacity
2D .0524 Subpart Da Subpart Db Subpart IIII Subpart Y Subpart OOO	 coal-fired boiler aux boiler emergency engines coal handling limestone handling	NSPS Requirements
2D .0530	all new sources	PSD review including BACT is required for a major modification
2D .0535	all sources	Emissions in excess of established permit limits that last for more than 4 hours require notification to the Director within 24 hours
2D .0540	limestone handling	Fugitive dust emissions
2D .0606	same as above	Quarterly excess emissions reports are to be used as an indication of good operations and maintenance of the ESP
2D .1111 Subpart ZZZZ	 emergency engines	Maximum Achievable Control Technology Requirements
2D .2500	coal-fired boiler	see Section 4.4.12
2D .1418	coal-fired boiler	NOx emissions cannot exceed 0.15 lb/mmBtu for gaseous and solid fuels and 0.18 lb/mmBtu for liquid fuels
2Q .0101	all sources at facility	A permit is required for all sources of air emissions not specifically exempted
2Q .0317(a)(1)	all sources at facility	PSD avoidance to prevent increase in NO_x and SO_2 emissions
2Q .0402	coal-fired boiler	Acid Rain emission limits

4.4.1 15A NCAC 2D .0503 – Particulates from Fuel Burning Indirect Heat Exchangers

This rule applies to installations burning fuel, including natural gas and fuel oils, for the purpose of producing heat or power by indirect heat transfer. The affected sources to which this regulation applies are the main coal fired boiler (ID Nos. ES-6) and the auxiliary boiler (ID No. ES-Aux6).

Allowable emissions of particulate matter from fuel burning indirect heat exchangers depend on the total facility-wide heat inputs from all indirect heat exchangers.

The facility-wide heat inputs are as follows:

Source	Heat Input (mmBtu/hr)
Unit 5	6,080 (existing)
Unit 6	7,850 (new)
ES-6 (AuxB)	71.5 (existing)
ES-Aux 6	190 (new)
Total	14,191.5

Therefore, according to the rule, the allowable emissions for facility-wide heat inputs greater than 10,000 mmBtu/hr are 0.10 lb/mmBtu.

4.4.2 15A NCAC 2D .0510 – Particulates From Sand, Gravel, or Crushed Stone Operations

The owner or operator of a sand, gravel, or crushed stone operation shall not cause, allow, or permit any material to be produced, handled, transported or stockpiled without taking measures to reduce to a minimum any particulate matter from becoming airborne to prevent exceeding the ambient air quality standards beyond the property line for particulate matter, both PM10 and total suspended particulates.

Fugitive non-process dust emissions from sand, gravel, or crushed stone operations shall be controlled by Rule 2D .0540.

The owner or operator of any sand, gravel, or crushed stone operation shall control process-generated emissions: (1) from crushers with wet suppression, and (2) from conveyors, screens, and transfer points, such that the applicable opacity standards in Rules 2D .0521 or .0524 are not exceeded.

4.4.3 15A NCAC 2D .0515 – Particulates From Miscellaneous Industrial Processes

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

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

or

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

where: E = allowable emission rate in pounds per hour
P = process weight in tons per hour

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

4.4.4 15A NCAC 2D .0516 - Sulfur Dioxide Emissions from Combustion Sources

Emissions of sulfur dioxide from any source of combustion that is discharged from any vent, stack, or chimney shall not exceed 2.3 pounds of sulfur dioxide per million BTU heat input.

4.4.5 15A NCAC 2D .0519 – Control of Nitrogen Dioxide and Nitrogen Oxide Emissions

NOx emissions shall not exceed 0.8 lb/mmBtu of heat input from any oil or gas-fired boiler with a capacity of 250 mmBtu/hr or more; or 1.8 lb/mmBtu of heat input from any coal-fired boiler with a capacity of 250 mmBtu/hr or more.

4.4.6 15A NCAC 2D .0521 - Control of Visible Emissions

The intent of this Rule is to prevent, abate and control emissions generated from fuel burning operations and industrial processes where 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 (except during startup, shutdowns, and malfunctions) when averaged over a six-minute period except that six-minute periods averaging not more than 87 percent opacity may occur not more than once in any hour nor more than four times in any 24-hour period.

4.4.7 15A NCAC 2D .0524 - New Source Performance Standards

See Section 4.2

4.4.8 15A NCAC 2D .0530 - Prevention of Significant Deterioration

See Section 4.1

4.4.9 15A NCAC 2D .0535 - Excess Emissions Reporting and Malfunctions

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

4.4.10 15A NCAC 2D .1111 - Maximum Achievable Control Technology

See Section 4.3

4.4.11 15A NCAC 2D .2500 – Mercury Rules for Electric Generators

North Carolina's "mercury rule" for existing and new electric steam generating units (EGUs) became effective on January 1, 2007.

This regulation has a "state-only" provision under Section 2D .2511 "Mercury Emission Limits" for new coal-fired boilers, which is a requirement to install and operate a best available control technology (BACT) for mercury. BACT as defined under this rule is an emissions limitation, which is determined on a case-by-case basis and based upon the maximum degree of reduction of mercury from coal-fired electric steam generating units that is achievable for such units taking into account energy, environmental, and economic impacts and other costs. BACT shall in no case result in emissions of any pollutant exceeding the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, or 63 of 40 CFR.

Separately, US EPA has promulgated emission standards for new EGUs under 40 CFR 60 Subpart Da on May 18, 2005 [70 FR 28606] with a revision made on June 9, 2006 [71 FR 33388].

The NSPS includes the following emission standards:

- 0.020 lb/GWh on an output basis when burning bituminous coal in EGUs other than IGCC
- 0.066 lb/GWh on an output basis when burning subbituminous coal in EGUs other than IGCC
- 0.016 lb/GWh on an output basis when burning coal refuse in EGUs other than IGCC

As included in the CAA Section 111(a)(1), the "standard of performance" (under NSPS) must reflect the degree of emission limitation achievable through the best system of emission reduction, taking into consideration the cost of achieving such reduction, any no-air quality health and environmental impacts, and energy requirements, and it must be adequately demonstrated in practice.

In formulating emission standards to limit Hg emissions from new coal-fired EGUs, EPA considered the performance of the control technologies for PM, SO_2, and NOx: fabric filter, ESP, FGD, SCR, and SNCR. After considering the available information, EPA determined that the technical basis (*i.e.*, the best system of emission reduction which the Administrator determines has been adequately demonstrated, or best demonstrated technology, BDT) selected for establishing Hg emission limits for new sources is the use of effective PM controls (e.g., fabric filter or ESP) and wet or dry FGD systems on subbituminous-, lignite-, and coal refuse-fired units; effective PM controls (e.g., fabric filter or ESP), wet or dry FGD systems, and SCR or SNCR on bituminous-fired units.

EPA rejected the sorbent injection controls for removal of Hg by concluding that the sorbent technologies (such as carbon injection) are currently not available for widespread or long-term use. Hence, EPA excluded any HG-specific technology in the NSPS.

The promulgated NSPS mercury emission standards are based on 1999 information collection request data (ICR). EPA determined that combination of technologies installed by a new source to comply with either PM, SO_2 or NOx emissions standards in NSPS would result into a maximum degree of reduction. EPA based the Hg emission standards on 90th percentile confidence level (i.e., Hg removal efficiency using BDT estimated to be achieved 90 percent of time).

Finally, EPA considered the cost of achieving the reductions in Hg emissions required by the new-source standards, the non-air quality health and environmental impacts arising from the implementation of the new-source standards and the energy requirements associated with the new-source standards and determined that they are all reasonable.

Duke included in a letter dated December 21, 2006 to the DAQ that their proposed technologies for the new coal fired boiler (ESP, FGD, and SCR) for different pollutants (PM, SO_2, and NOx) represent the BDT for HG emissions for this kind of emission unit under NSPS Subpart Da.

After considering the above, DAQ concludes that the criteria for determining BACT for Hg under this regulation substantially matches the criteria for determining BDT for Hg under NSPS. DAQ also agrees with the Permittee that the above technologies do meet the NSPS Subpart Da requirements for control of Hg emissions for the EGUs. Therefore, DAQ proposes to approve the following BACT for Hg emissions as a "state-only" requirement for the proposed coal fired boiler:

Pollutant	Coal Type	BACT Emission Limit	Control Technology
Mercury	Bituminous	0.020 lb/GWh on an output basis	dry and wet ESPs, wet FGD and SCR
	Subbituminous	0.066 lb/GWh on an output basis	dry and wet ESPs, and wet FGD
	Coal refuse	0.016 lb/GWh on an output basis	dry and wet ESP, and wet FGD

4.4.12 15A NCAC 2D .1418 – New Electric Generating Units, Large Boilers, and Large I/C Engines (NOx Allocations)

This regulation is North Carolina's NOx SIP-Call requirement and applies to any fossil fuel fired stationary boiler, combustion turbine, or combined cycle system permitted after October 31, 2000, serving a generator with a nameplate capacity greater than 25 megawatts electrical and selling any amount of electricity. Therefore the rule applies to the main coal-fired boiler (ID Nos. ES-6).

Emission Limits
Emissions of nitrogen oxides shall not exceed 0.15 lb/mmBtu for gaseous and solid fuels and 0.18 lb/mmBtu for liquid fuels or shall not exceed BACT, whichever requires the greater degree of reduction. If emission allocations are not granted under 15A NCAC 2D .1421 or are not equal to or greater than the emissions of nitrogen oxides of the source for that ozone season, until revised under 15A NCAC 2D .1420, the facility must acquire emission allocations of nitrogen oxides using the procedures under 15A NCAC 2D .1419 from other sources sufficient to offset emissions from the new boiler. Sources shall comply with the requirements of 15A NCAC 2D .1418 using the nitrogen oxide budget trading program set out in 15A NCAC 2D .1419.

Compliance
The facility must assure compliance with 15A NCAC 2D .1418 by determining nitrogen oxide emissions in tons per ozone season using a continuous emissions monitoring system (CEMS) that meets the requirements of 40 CFR Part 75 Subpart H, with such exceptions as allowed under 40 CFR Part 75, Subpart H or 40 CFR 96. NOx allowances to cover emissions from each source must be held in the source's compliance account as of November 30 of each year.

4.4.13 15A NCAC 2Q .0101 - Required Air Quality Permits

This regulation requires the owner or operator of all sources for which there is an ambient air quality or emission control standard, that is not exempted from permit requirements, to apply for an air quality permit. The owner or operator of a source required to have a permit shall not begin construction or operation of the source without first obtaining a permit.

4.4.14 15A NCAC 2Q .0317(a)(1) – Avoidance Condition for PSD

Duke is proposing to net out of PSD for NO_x and SO_2 by taking a practically-enforceable PSD avoidance limit on future facility-wide NO_x and SO_2 emissions to keep those emissions from increasing beyond the baseline facility-wide values. In order to avoid applicability of PSD, Units 1-4 must be shutdown upon startup of the new boiler (Unit 6) and combined Unit 5 and 6 emissions of NO_x shall not exceed 4,871 tons per year and emissions of SO_2 shall not exceed 25,186 tons per year.

4.4.15 15A NCAC 2Q .0402 - Acid Rain Permitting Procedures

The main boiler will be subject to federal Acid Rain emission limits. However, the Acid Rain applications are not due until 24 months prior to operation. These requirements will be added to the permit when Duke submits the Acid Rain application.

SECTION 5.0

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 Summary

The proposed sources subject to the Best Available Control Technology (BACT) requirements include the main coal-fired boiler, the auxiliary boiler, cooling towers, diesel engines and material handling point and fugitive emission sources. This section presents the PSD BACT analysis and proposed BACT limits for these proposed new emission sources.

Based on the controlled emission rates of the PSD regulated air pollutants shown in Table 4-4, the proposed modification will produce significant emissions of, and is therefore subject to PSD review for CO, PM_{10}, VOCs, sulfuric acid mist (H_2SO_4) and lead (Pb). Since Duke is netting out of PSD for NO_X and SO_2 (as previously discussed), PSD review is not triggered and a BACT analysis for these pollutants is not required. However, the proposed Unit 6 boiler will be equipped with low NO_x burners with overfire air, and state-of-the-art selective catalytic reduction (SCR) and FGD scrubbers for control of NO_X, SO_2 and acid gases. And the auxiliary boiler will be equipped with low NO_x burners with overfire air for NOx control to meet emission requirements other than BACT. The BACT analysis will address applicable control techniques for these pollutants. Mercury is not a PSD pollutant and is not subject to PSD or BACT review. However, the emission control systems that constitute BACT for the other regulated pollutants will effectively control emissions of mercury.

This BACT evaluation has concluded that for the coal–fired boiler, BACT will require the use of good combustion for control of CO and VOC, spray dryer lime injection upstream of a fabric filter for targeted control of H_2SO_4, and a fabric filter baghouse for particulate control, including lead. For the auxiliary boiler, BACT will consist of good combustion for CO and VOC, and the use of 0.05% sulfur No. 2 fuel oil to limit emissions of particulate and Pb, and limiting the hours of operation. BACT for the cooling towers (which only emit particulates) will require state-of-the-art drift eliminators. BACT for filterable particulate emissions from materials handling operations will require compliance with the applicable NSPS requirements to coal preparation operations (Subpart Y) and applicable to limestone processing (non-metallic mineral processing, Subpart OOO), and the use of partially enclosed conveyors, dust suppression and dust collection (e.g. fabric filters).

A summary of the proposed and final BACT emission limits for the main boiler is presented in Table 5-1.

Table 5-1
BACT Emission Limits and Control Technology Summary for PC Boiler

POLLUTANT	BACT EMISSION LIMIT		AVERAGING PERIOD	BACT TECHNOLOGY
	PROPOSED BY DUKE (lb/mmBtu)	FINAL BY DAQ (lb/mmBtu)		
PM_{10}	0.015 filterable 0.024 total	0.012 filterable 0.018 total	three 1-hr stack tests	spray dry absorber followed by fabric filter baghouse
visible emissions	20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity		6-minutes	fabric filter baghouse
CO	0.15	0.12	three 1-hr stack tests	good combustion
VOC	0.004	0.004	three 1-hr stack tests	good combustion
H_2SO_4	0.005	0.005	three 1-hr stack tests	spray dry absorber followed by fabric filter baghouse
Pb	0.000022	0.000022	three 1-hr stack tests	fabric filter baghouse

5.2 Introduction

Each pollutant subject to a PSD review must meet the criteria of Best Available Control Technology (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 NSPS (40 CFR Part 60) and NESHAPS (40 CFR Part 61).

Under PSD regulations, the basic control technology requirement is the evaluation and application of BACT. BACT is defined in pertinent part as follows [40 CFR 51.166(b)(12)]:

> ***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.***

As evidenced by the statutory definition of BACT, this technology determination must include a consideration of numerous factors. The structural and procedural framework upon which a decision should be made is not prescribed by Congress under the Act nor by the EPA through any rule. DAQ makes their BACT determinations based on an evaluation of the statutory factors contained in the definition of BACT in the Clean Air Act. The following are passages from the Legislative History of the Clean Air Act Amendments of 1977 and 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 judgement. 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 in 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 judgement at the State level.** [**emphasis added**]. This flexibility should allow for such differences to be accommodated and still maximize the use of improved technology.

Additionally, as a result of the EPA remand involving the North County Resource Recovery project in Region IX, the effects of non-regulated PSD pollutants, such as toxic air pollutants, may be considered in determining if the BACT otherwise being prescribed for a regulated pollutant still represents an appropriate level and type of control.

As part of the national interest in new coal-fired power plants, some have asked whether Integrated Gasification Combined Cycle (IGCC) should be considered in the BACT analysis during the permitting process in accordance with the statutory definition of BACT (Clean Air Act (CAA) section 169). North Carolina has determined, in reviewing statutory language and EPA guidance, that inclusion of IGCC as a BACT technology is not appropriate. See Appendix F for a discussion of the reasons why DAQ has made this determination at this time.

The EPA has issued guidance encouraging all PSD applicants to use the "top-down" approach to BACT. While the EPA Environmental Appeals Board recognizes the “top-down” approach for delegated state agencies,[8] this procedure has never undergone rulemaking. As such, the “top-down” process is not binding on fully approved states, including North Carolina.[9] In this case, the applicant's BACT analysis is consistent with the EPA based "top-down" approach. However, NC DAQ 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 order to identify potential controls, previous BACT determinations, as well as EPA's RACT/BACT/LAER Clearinghouse (RBLC), EPA’s spreadsheet for proposed coal-fired utility PSD projects and draft permits for similar PC boilers that will burn eastern or Northern Appalachian bituminous coals, were reviewed.

5.3 BACT Analysis for PC Boilers

Duke is proposing to use a combination of a spray dry absorber (SDA) using a lime slurry injection followed by a fabric filter for the control of sulfuric acid. In this targeted acid gas control application, preferential control of acid gases is achieved by controlling the amount of water (temperature reduction through evaporation) based on the acid dew point of the flue gas. Little sulfur dioxide will be removed as compared to a conventional spray dry FGD system because the spray dryer does not operate at the low approach to adiabatic saturation temperature and because the limited amount of lime injection will preferentially react with sulfuric acid. In a typical SDA, the flue gas passes through a spray dryer vessel where it encounters a fine mist of lime slurry. The lime slurry is injected into the SDA through either a rotary atomizer or fluid nozzles. The moisture in the droplets evaporates and the lime reacts with the acid gases in the flue gas to form calcium salts. A fabric filter then allows for further reaction of the lime with the acid gases in the flue gas. This is due to the layer of porous filter cake on the surface of the filter that contains the reagent that all flue gas must pass through. This allows for increased efficiency of control of sulfuric acid mist, hydrogen chloride and mercury as compared to wet scrubbers.

According to Duke, these proposed BACT controls are an innovative use of technology that provides several environmental advantages. Use of the spray dryer system will allow the facility to recycle process wastewater from the wet scrubber systems installed on Unit 5 and Unit 6 for SO_2 control. This will eliminate the need for a wastewater treatment system on Unit 6 and on Unit 5 when Unit 6 is operating. That will reduce or eliminate the need for a wastewater discharge to the environment. The recycled water will also provide flue gas cooling prior to the wet scrubber, which will reduce the overall water consumption needed to maintain scrubber operation.

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[8] See http://es.epa.gov/oeca/enforcement/envappeal.html for various PSD appeals board decisions including standard for review.

[9] North Carolina has full authority to implement the PSD program, 40 CFR Sec. 52.1770.

5.3.1 BACT Analysis for PC Boiler for PM_{10}

The composition and amount of particulate matter emitted from coal-fired boilers are a function of many variables including: firing configuration, boiler operation, coal properties and emission controls. Particulate matter will be emitted from the pulverized coal-fired boiler as a result of entrainment of incombustible inert matter (ash) and condensable substances such as acid gases. Particulate matter smaller than 10 microns (PM_{10}) has historically been regulated from coal-fired boilers as the filterable, or front-half catch (per EPA test method) only. In the past many permits contained only filterable limits and required stack testing for only filterable particulate for demonstration of compliance. However, DAQ and EPA now require air quality impacts under the PSD review process to consider both filterable and condensable fractions of PM_{10}. Particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) is not subject to BACT limitations but technologies to control PM_{10} also have been shown to be effective at capturing $PM_{2.5}$.

Control technologies are primarily designed to capture solid or filterable materials and any capture of condensable emissions is secondary. Some constituents of condensable PM_{10}, including sulfuric acid mist, VOCs, Hg, HCl and HF, are regulated separately and typically addressed through use of control technologies (such as Wet ESPs).

<u>PM_{10} Control Alternatives for PC Boiler</u>

Duke's review of EPA's RBLC and recent permits as shown in Table 5-3 indicates general levels of PM control that may be achieved with various combinations of control technology. Emission levels and control technologies for pulverized coal combustion have been identified and ranked.

Table 5-3
Ranking of PM Control Technology Options for PC Boilers

Control Technology Option	Emission Level (lb/mmBtu)	Technically Feasibility for Pulverized Coal-fired Boilers?
Fabric Filter	0.01 to 0.02 for filterable PM_{10}	yes
Dry ESP	0.015 to 0.030 for filterable PM_{10}	yes
Dry ESP followed by polishing Wet ESP	0.010 for filterable PM_{10}, 0.030 for total PM_{10}	yes
High energy wet scrubber	Not determined	No applications in the last 15 years to large coal-fired boilers

Emission levels represent target steady-state values at base load, for front-half (filterable) only. Inclusion of the condensable fraction is thought to double the particulate emission rate for coal-fired boilers.

Dry Electrostatic Precipitators (ESPs)

ESPs remove particulate matter from the flue gas stream by charging fly ash particulates with a high direct current (dc) voltage and attracting these particles to charged collection plates. A layer of collected particulate forms on the collecting plates (electrodes) and is removed by rapping the electrodes. The collected particulate drops into hoppers below the precipitator and is periodically removed by the fly ash handling system.

Because of their modular design, ESPs can be applied to a wide range of system sizes and should have no adverse effect on combustion system performance. The operating parameters that influence ESP performance include: fly ash mass loading, particle size distribution, fly ash electrical resistivity, and precipitator voltage and current. Other factors that determine ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies of approximately 95% for fine particles (less than 0.1 microns) and greater than 99% for coarse particles (greater than 10 microns). ESPs are considered a technically feasible option for the proposed Cliffside boiler. Based on operating experience at other large bituminous coal-fired units, it is anticipated that the lowest post-control PM_{10} emission rate that could be consistently achieved with ESP technology is 0.015 lb/MMBtu, as determined via periodic stack testing using Reference Method 5. Gaseous species that do not condense at ESP temperatures (but would in an ice bath of a Method 202 train during testing) pass through and are not collected in an ESP.

Fabric Filter

Fabric filters are widely used for particulate control from PC boilers and are capable of over 99% control efficiency. Flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are the most common type of fabric filter. The dust cake that forms on the filter from the collected particulate matter can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Bags may be 20 to 30 ft long and 5 to 12 inches in diameter. Groups of bags are placed in isolatable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter. PC units with baghouses have also been permitted for filterable PM emissions in the range of 0.015 lb/mmBtu.

Fabric Filter with Spray Dry Absorber

A fabric filter baghouse is the preferred particulate control device in applications involving use of a SDA because flue gas passing through the filter cake enhances the utilization of the sorbent and removal of the gases pollutants. Emission rates of filterable PM_{10} are expected to be equivalent (in terms of lb/mmBtu) for a baghouse operating with or without SDA. However, operation of an SDA ahead of a fabric filter baghouse offers the advantage of reducing the flue gas temperature below the sulfuric acid gas dew point, and will therefore provide the opportunity to collect condensable PM_{10} emissions in the form of sulfuric acid. Hydrogen chloride (HCl) gas is also collected by the spray dryer/baghouse combination. Control of condensable emissions will be achieved by maintaining temperature below the acid dew point and providing sufficient sorbent to react with the acid gas species.

Wet Electrostatic Precipitator

There are no known applications where wet ESPs have been used as a primary particulate collection device on a coal-fired utility boiler. Wet ESPs have been proposed as a polishing device following a baghouse or dry precipitator and a wet SO_2 scrubber to capture condensed fine particulate from coal-fired boilers. The primary purpose has been to emove sulfuric acid mist that will form at the reduced temperature through the scrubber. Hydrochloric acid (HCl) and hydrofluoric acid (HF) are the other two "condensable" fraction species that are likely to condense at wet scrubber temperatures, but those are very soluble and are effectively captured within a wet scrubber system. If sulfuric acid is removed through other processes prior to passing through the wet scrubber (such as a spray dry absorber), condensed sulfuric acid mist in the flue gas leaving the scrubber will be insignificant and there would be no basis for installation of a "polishing" device to remove condensed sulfuric acid. In a WESP, the flue gas is saturated and liquid water is used to rinse the collected PM_{10} from the plates or tubes to a sump at the bottom. Here, conventional water treatment processes are used to remove the captured pollutants so that the water may be reused in the WESP. The use of a water flush rather than mechanical rapping in a dry ESP provides greater cleaning of the plates which promotes higher electric fields and thus greater collection of the fine particulate.

Disadvantages of WESP's include a cooler plume (lower plume rise and dispersion), cost, and the evaporative use of greater quantities of water. The corrosive nature of the condensed acid gases would require use of high performance alloys and would require careful attention to operation and maintenance to avoid premature failure. WESP's have been employed for years for primary control of aerosol and fine particulate emissions in industrial applications, but are a relative newcomer to the utility boiler sector. They are commercially available from multiple vendors and have been permitted for several new PC coal units as a secondary or polishing collector, but there is very limited actual operating experience.

Energy, Environmental and Economic Impacts

The ESP and WESP will require power to charge particles for collection on the plates. A fabric filter would require additional fan power due to the added pressure drop across the filter in the gas stream. The differences between alternatives is insignificant and does not affect selection of BACT for $PM_{10.}$ A cost analysis was not required since the PM_{10} permit limits have been established at the lowest levels previously determined to be BACT for similar coal-fired boilers (see Determination below).

PM_{10} BACT Determination for PC Boiler

Both ESP and fabric filters are proven filterable PM10 control systems, and either control system can be designed to achieve a controlled PM10 emission rate of 0.015 lb/mmBtu. WESPs are a relatively new application to PC boilers and are not well demonstrated in this application.

Duke proposes a spray dryer absorber followed by a fabric filter, which represents the top level of control for fine particulate. Condensable emissions of sulfuric acid mist will be removed in gaseous state prior to the fabric filter, as discussed below. While these separate components are proven and reliable for use on a coal-fired boiler, this combination of control is cutting edge technology for targeted removal of sulfuric acid upstream of the particulate collector, and Duke states that they are not aware of any long-term test data for total PM_{10} from similar PC boilers operating with lime injection for acid gas capture followed by a fabric filter, and utilizing the planned range of coals. The reliable measurement of PM_{10} from a saturated stack is also difficult.

Duke has proposed a total PM_{10} limit of 0.024 lb/mmBtu for Cliffside Unit 6, based on a limit of 0.015 lb/mmBtu for filterable PM_{10}, and adding 0.009 lb/mmBtu for non-otherwise regulated condensable PM_{10} (i.e. excluding H2SO4, HF, HCl, VOC). Compliance will be demonstrated through periodic testing for filterable emissions using EPA Reference Method 5 or 17 and Method 202, including any modifications necessary due to the saturated conditions in the stack. To determine compliance with the limit including condensable emissions, Duke proposes to use Reference Method 202 with modifications and procedures to eliminate any “pseudo-condensable” particles which are known to cause interference. Duke states that these limits provide a reasonable margin of compliance to allow for variation in calculated emissions due to the inherent problems of conducting a stack test under non-ideal conditions, and are within the range of BACT standards in recent permits.

DAQ has reviewed RBLC data for PC fired utility boilers for the period January 1, 2001 through July 30, 2007 to evaluate the BACT for PM/PM_{10} emission limits. Appendix D includes a summary of RBLC data. The data shows the lowest limits to be 0.012 lb/mmBtu for filterable PM_{10} emissions and 0.018 lb/mmBtu for total PM_{10} emissions.

In addition, more recent information on PM/PM_{10} limits for several similar recent projects with filterable limits of 0.015 lb/mmBtu and/or total PM/PM_{10} limits of 0.018 lb/mmBtu or higher is shown in Table 5-4:

Table 5-4
Selected Recent Pulverized Coal Power Plant Projects

State	Description	Permit Status	PM Emissions Limits
KY	Thoroughbred Generating Station (Peabody Energy); Two 750-MW PC subcritical units; Bituminous coal (mine-mouth project)	Final PSD permit issued 10/02. Permit appealed. Permit upheld 4/06. Lawsuit filed. [Construction has not commenced.]	Final permit limits: PM/PM_{10} = 0.018 lb/MMBtu (3-hour) [supposedly includes condensables; not clearly specified]
KY	Louisville Gas & Electric, Trimble County Generating Station; One 750-MW PC supercritical unit; Bituminous coal or blend of bituminous and subbituminous	Final PSD permit issued 1/06; permit appealed	Final permit limits: PM/PM_{10} = 0.018 lb/MMBtu (3-hour) with condensables
SC	Santee Cooper, Cross Generating Station; Two 660-MW subcritical units; Bituminous coal and petcoke	Final PSD permit issued 2/04	Final permit limits: PM = 0.015 lb/MMBtu (3-hour) filterable only, 0.018 lb/MMBtu (3-hour) with condensables
SC	Santee Cooper, Pee Dee Generating Station; Two 660-MW supercritical units; Bituminous coal and petcoke	Permit application submitted 7/06	Proposed rates: PM/PM_{10} = 0.018 lb/MMBtu (6-hour) with condensables
NC	Duke Power, Cliffside Generating Station; Two 800-MW supercritical units; Bituminous coal or blend of bituminous and subbituminous	Permit application submitted 12/05	Proposed rates: PM/PM_{10} = 0.015 lb/MMBtu (3-hour) filterable only
GA	Longleaf Energy (LS Power); Two 600-MW subcritical units; Primarily PRB subbituminous coal but could also include blend with bituminous coal and wastewater treatment sludge from nearby pulp mill	Permit application submitted 11/04; (Draft PSD permit expected soon)	Likely permit limits[a]: PM/PM_{10} = 0.015 lb/MMBtu filterable only, 0.033 lb/MMBtu with condensables
WV	Longview Power; One 600-MW supercritical unit; Bituminous coal	Final PSD permit issued 3/04	Final permit limits: PM/PM_{10} = 0.018 lb/MMBtu (6-hour) with condensables
IL	Prairie State Generating (Peabody Energy); Two 750-MW subcritical units; Bituminous coal (mine-mouth project)	Final PSD permit issued 1/05	Final permit limits[b]: PM = 0.018 lb/MMBtu

[a] Draft permit has not yet been issued. Permitting engineer said on 7/12/06 that these are the likely limits that will be in the draft permit.

[b] This information is from EPA's national coal-based power plant spreadsheet and is all the information currently available.

Based on the above, DAQ has established a BACT limit for PM_{10} of 0.012 lb/mmBtu for filterable emissions and a total PM_{10} emissions limit of 0.018 lb/mmBtu including condensable emissions for the proposed new boiler at Cliffside based on the RBLC data showing these emission levels to be the lowest permitted emission rates for similar sources. DAQ believes condensables should be included in the limit and that these limits are achievable, even though none of the facilities that have a total PM_{10} limit of 0.018 lb/mmBtu have begun operation and therefore the ability to meet that emissions rate has not been demonstrated.

Duke is concerned that the proposed PM_{10} limits relate to both the ability of demonstrated, commercial control systems to achieve very low emissions of particulates, including condensables, and known concerns with test Method 202. (Attached EPA Method 202 Improvement Initiative document). Duke states that there are many problems they face especially with control and measurement of condensable emissions including various particulate species that will be captured in the test apparatus that should not be counted as condensable particulate and that at very low allowable emission rates, it is extremely important that the test method not capture any so-called “pseudo-particulate.” Even if those pseudo-particulates are eliminated, the control margin for other condensable emissions (sulfuric acid and organic compounds) is very tight and it may be very difficult to achieve total actual emissions below 0.024 lb/mmBtu. Duke discusses this issue in their letter (Revised Submittal on PM_{10} BACT Analysis) to Dr. Don van der Vaart, from Rick R. Roper dated November 20, 2006.

Because of some uncertainty regarding whether such a low filterable and condensable PM_{10} emission rate is achievable in practice, the permit includes a condition that will allow DAQ to set a higher emissions limit if the proposed limit cannot be achieved as demonstrated by the initial performance test. This allows an adjustment of the 0.012 lb/mmBtu filterable PM_{10} limit to a level not to exceed 0.015 lb/mmBtu after initial operation if testing demonstrates that it is not feasible to meet the emissions rate despite proper operation and optimization of the control equipment. Further, if the actual condensable portion of PM_{10} causes the total PM_{10} emission rate of 0.018 lb/mmBtu to be exceeded, the total PM_{10} allowable emission rate may be adjusted to a level not to exceed 0.024 lb/mmBtu, which is the level at which the modeling was performed. Also, the condition will allow for consideration of an alternate PM_{10} test method other than Reference Method 202, if such methods are approved by DAQ based on technical review. Duke is concerned that measurement of condensables presents a problem of collection of secondary particulates (sulfates and nitrates) which are technically not part of PM_{10} because they form artificially in Method 202 testing and would not form in the air pollution control train or stack. Gaseous PM_{10} species that do not condense at ESP temperatures (but would in an ice bath of a Method 202 train) can pass through an ESP and are not collected with this technology.

The permit for AES-PR (a CFB) addressed this issue similarly. AES’s permit limited filterable PM_{10} emissions to 0.015 lb/mmBtu and allowed stack testing to determine an achievable total PM_{10} emission limit. Stack tests showed that filterable PM_{10} emissions were below 0.015 lb/mmBtu; however, based on stack test results, AES received an administrative change to their permit to set the total PM_{10} emission limit at 0.030 lb/mmBtu a value that accounts for the additional contribution of measured condensable PM_{10} at that facility.

Note: US EPA recently adopted a Reference Method for continuous PM monitoring as under 40 CFR 60 Appendix A spec. 8. Duke tates that that implementation of CEM’s for PM10 is in its infancy, and there are few, if any, facilities to date that are required to base continuous compliance on such monitors. These monitors have not been shown to reliably represent the actual particulate emissions, and may not be capable of measuring PM10 emissions from a saturated stack. Duke Energy is not proposing the use of continuous particulate monitoring due to these concerns; although the option to use CEMs is allowed by the permit.

5.3.2 BACT Analysis for PC Boiler for CO and VOCs

Combustion is a thermal oxidation process in which carbon, hydrogen, and sulfur contained in a fuel combine with oxygen in the combustion zone to form CO_2, H_2O, and SO_2. CO is generated during the combustion process as a result of incomplete thermal oxidation of the carbon contained within the fuel. VOCs are also generated due to incomplete combustion of fuel.

High levels of CO and VOC emissions result from poor burner design or sub-optimal firing conditions. With combustion technology/design control, formation of CO and VOC in the PC boiler is minimized by good combustion efficiency through optimum design and operation. This includes proper air-to-fuel ratios, and a boiler design that provides the necessary temperature, residence time and mixing conditions in the combustion zone.

Care must be taken when incorporating combustion design changes to reduce both NO_X and CO or VOC emissions. Combustion modifications associated with reduction of CO and VOC emissions can increase NO_X emissions and vice versa. For example, the use of low-NOx burners reduces flame temperature and thus reduces the NO_X formation in the combustion zone, but the same technique also leads to increases in products of incomplete combustion such as CO and VOCs. A good balance between these air pollutants must be achieved in order for combustion modification to be useful.

CO and VOC Control Alternatives for PC Boiler

Duke has reviewed the control technologies for CO and VOC and ranked them as shown in Table 5-5 below using the RBLC data including the recently issued air permits for PC boilers:

Table 5-5
Ranking of CO and VOC Control Technologies for PC Boilers

Control Technology Option	Emission Level (lb/mmBtu)	Technically Feasibility for Pulverized Coal-fired Boilers?
Combustion controls	0.05[1] to 0.15 (CO) 0.003 to 0.02 (VOC)	Yes
Catalytic oxidation	-	No
Thermal oxidation	-	No
EMx™	-	No

1. As per Duke, the 0.05 value listed is for the original W. A. Parrish units, and was low at the expense of an abnormally high NO_x rate. No other PC boiler since has been permitted below 0.1 lb CO / million Btu, and such level can not be achieved on boilers that are required to also employ BACT for NO_x. Lower CO emissions can be achieved with Western sub-bituminous coals due to their inherently lower NO_x formation characteristics.

Combustion Controls

Optimization of the design, operation, and maintenance of the furnace and combustion system is the primary mechanism available for lowering CO and VOC emissions. This process is often referred to as combustion controls. The furnace/combustion system design on modern PC-fired utility boilers provides all of the factors required to facilitate complete combustion. These factors include continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber. As a result, a properly designed furnace/combustion system is effective at limiting CO and VOC formation by maintaining the optimum furnace temperature and amount of excess oxygen.

Unfortunately, the addition of excess air and maintenance of high combustion temperatures for control of CO and VOC emissions will lead to an increase of NO_X emissions. Consequently, typical practice is to design the furnace/combustion system (specifically, the air/fuel mixture and furnace temperature) such that CO and VOC emissions are reduced as much as possible without causing NO_X levels to significantly increase. Proper operation and maintenance of the furnace/combustion system will help to minimize the formation and emissions of CO and VOC by ensuring that the furnace/combustion system operates as designed. This includes maintaining the air/fuel ratio at the specified design point, having the proper air and fuel condition at the burner, and maintaining the fans and dampers in proper working condition.

Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of CO and VOCs. The catalytic oxidation system is typically a passive reactor, which consists of a honeycomb grid of metal panels, generally coated with platinum or rhodium. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (450^0F - 1200^0F). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to lower the activation energy necessary for complete oxidation of these incomplete combustion byproducts to carbon dioxide and water. The active component of most catalytic oxidation systems is platinum metal, which has been applied over a metal or ceramic substrate. As with SCR, minimization of pressure drop is a major design criterion; therefore, honeycomb catalyst designs are common.

The primary limitation that may preclude the use of catalytic oxidation in the PC fired utility boiler application is frequent, wide load variations, which will reduce catalyst efficiency and may cause thermal shock degradation of the catalyst.

A major operating drawback of the catalytic oxidizer is that fine particles suspended in the exhaust gases can foul and poison the catalyst. The problem of catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device, however, this would require reheating the exhaust gases to the required operating temperature for the catalytic process. Another significant disadvantage of the catalytic oxidizer is that SO_2 in the flue gas stream may be oxidized to form SO_3. The resulting SO_3 may react with the moisture in the flue gas to create sulfuric acid mist. It should be noted here that the catalytic oxidation is generally utilized for CO and VOC emission reductions in combined-cycle combustion turbine power plants and has not been demonstrated and is not commercially available for use on PC-fired utility plants.

Thermal Oxidation (TO)

Thermal oxidation requires heat (temperatures typically between 1400^0F to 1600^0F) and oxygen to convert CO and VOC in the flue gas to CO_2 and H_2O. There are two general types of TO that are used for the control of CO and VOC emissions: regenerative thermal oxidization and recuperative thermal oxidization. TO has generally been utilized for emission reductions of CO and VOC in non-combustion sources. None of the above types of TO have been demonstrated in practice on full scale operations nor are they commercially available for use on PC-fired utility plants. In addition, there are significant secondary impacts and other issues that would preclude the use of this technology as an emissions reduction technology for CO and VOC for PC-fired utility boilers.

EMx™

EMx™ (previously SCONOx™) is a technology that has been widely discussed for application to many types of sources, however to date, there are only two known applications existing on small gas turbine cogeneration systems. Like catalytic oxidation, this technology has never been applied or even tested for application on PC-fired utility boilers. EMx™ actually utilizes the same CO reduction technology as catalytic oxidation as discussed above. The EMx™ bed incorporates a coating of the same catalyst material, primarily to oxidize NO to NO_2 but with the side benefit of also destroying CO. EMx™ therefore has all the limitations cited above for catalytic oxidation, but is even further from consideration as transferable technology for PC fired utility boilers.

CO and VOC BACT Determination for PC Boiler

Duke Power has proposed an emission limit of 0.15 lb/mmBtu and the good combustion control practices as BACT for CO. For VOCs, Duke has proposed an emission limit of 0.004 lb/mmBtu and the good combustion control practices as BACT. Duke has argued that the proposed emission limits are within the range of recently approved BACT for similar sources, and they allow capturing variability in coal supply and balancing emission reductions of CO and VOCs, and NO_X. Duke contends that the achievable CO emissions from PC utility boilers are generally insensitive to coal type but are inversely proportional to level of NO_X control achievable using the combustion control, essentially concluding that it is easier for a utility boiler which uses subbituminous coal (with an inherent lower NO_X) to achieve lower CO emissions than a utility boiler which burns eastern bituminous coal.

DAQ has reviewed RBLC data for PC fired utility boilers for the period January 1, 2001 through July 30, 2007 to evaluate the BACT for CO and VOCs. Appendix D includes a summary of RBLC data.

The data indicates that the CO limits range from 0.1 to 1.26 lb/mmBtu for PC-fired utility boilers, with 0.15 lb/mmBtu being the most common limit. It should be noted that there are two recent BACT determinations for retrofit PC fired utility boilers (e.g. installing low-NOx burners, over-fire air, etc.) [IA-0080 and IA-0081], which have included very high BACT emission limits of 0.42 lb/mmBtu and 1.26 lb/mmBtu. Since the proposed Cliffside boiler is a new PC fired utility boiler, inclusion of these retrofit determinations would not allow true comparison for setting BACT for CO. Therefore, these determinations have been excluded from further review. After removing these two BACT determinations, the CO limits vary between 0.1 to 0.33 lb/mmBtu.

The data also suggests that the VOC limits range from 0.0027 to 0.02 lb/mmBtu for PC fired boilers, with 0.0036 lb/mmBtu being the most common limit. Also, the data indicates good combustion control (GCC) as the only technology deemed to be BACT for both CO and VOCs, concluding that no PC fired utility boilers have recently been permitted with post-combustion control either for CO or VOCs.

Based on the above, DAQ believes that GCC is the most effective and the only technically feasible technology on PC-fired utility boilers, and there are no energy, environmental, or economic impacts that would preclude the use of GCC on these boilers. Therefore, DAQ proposes to approve a CO emission limit of 0.12 lb/mmBtu and a VOC emission limit of 0.004 lb/mmBtu using GCC for both pollutants, representing BACT for the boiler. The CO emission rate is lower than almost all previous determinations and the VOC rate is similar to most previous determinations. DAQ believes that this determination is consistent with recent BACT determinations and, at the same time, allows the GCC operational flexibility needed in order to maintain an optimum balance between CO/VOCs and NO_X emissions. That is, Duke has an incentive to keep NO_X emissions as low as possible in order to comply with the NO_X PSD avoidance cap (for which Duke has based their ability to net out of NO_X on an expected emission rate of 0.07 lb/mmBtu) as well as the system-wide cap on NO_X emissions under the Clean Smokestacks Act as discussed in Section 4.1.1.2. With an emission rate at the very low end of previous BACT determinations for NO_X, DAQ does not believe it is practical to expect both NO_X and CO/VOCs to be at the low end of previous determinations. This can be seen by comparing previous NO_X and CO/VOC emission determinations.

5.3.3 BACT Analysis for PC Boiler for H_2SO_4

Emissions of sulfuric acid mist are generated in fossil fuel-fired sources from the oxidation of sulfur present in the fuel. Sulfuric acid mist is typically generated when sulfur trioxide (SO_3) in the flue gas, reacts with water to form sulfuric acid. The proposed boiler will generate SO_3 during the combustion process, and the SCR catalyst will further oxidize SO_2 in the flue gas to SO_3. As the SO_3 is cooled it forms H_2SO_4. It is collected in some form (i.e. NH_4HSO_4, H_2SO_4, SO_3, Salts, PM_{10}) particularly through the air pollution control system.

H_2SO_4 Control Alternatives

Sorbent Injection

An alkali sorbent can be injected into the flue gas before the particulate collection to neutralize sulfuric acid in the flue gas. The sorbent is then collected downstream in the particulate control device. It has been reported that, depending on the particular equipment configuration, collection efficiencies of 10% – 50% may be possible using this technique.

Spray Dryer (SDA) with Targeted Acid Gas Control

In the case of a spray dryer targeted for acid gas control, SO_3 will condense and react with lime in the absorber. Because SO_3 and HCl are much more reactive than SO_2, approximately 90% of the SO_3 and a large percentage of the HCl will be removed from the flue gas in the SDA and subsequent reactions in the fabric filter in a system designed primarily form capture of these acid gases.

Operation of a SDA is discussed in Section 5.3. Sulfuric acid emissions of 0.005 lb/mmBtu or less can be achieved with proper process control.

Wet FGD

In the case of wet FGD, SO_3 entering the wet scrubbers will react with water and create micron sized sulfuric acid droplets. Some of these droplets can pass through the spray levels and the mist eliminator, and be emitted as sulfuric acid mist. Some of the sulfuric acid droplets will react with limestone in the wet scrubber, but because the droplets are so small, many of the droplets will not come into contact with limestone. Industry experience suggests that approximately 40% of the potential sulfuric acid mist will be removed in the wet FGD.

Wet ESP

A wet ESP can also be used to control aerosol sulfuric acid mist once it has been condensed. It is projected that wet a WESP could reduce the potential sulfuric acid mist emissions by approximately 90%. However, because of the very minimal operating experience of wet ESPs on large utility boilers, the removal efficiency is not well documented for extended operating periods.

H_2SO_4 BACT Determination for PC Boiler

Duke states that they can achieve the best level of control for sulfuric acid mist through use of a spray dryer using lime slurry injection followed by a fabric filter. While a WESP may be capable of similar reductions, WESPs have not been well demonstrated on PC boilers. Duke proposes to control sulfuric acid mist emissions through a SDA lime injection system upstream of a fabric filter baghouse, and is proposing a sulfuric acid mist BACT emission rate of 0.005 lb/mmBtu. DAQ's review of recently permitted projects indicates the Thoroughbred Project in Kentucky, using bituminous coal, has an emission rate of 0.00497 lb/mmBtu (30-day average) and the Prairie State Project in Illinois, using Illinois No. 6 coal, has an emission rate of 0.005 lb/mmBtu (3-hour block average); both projects include a wet scrubber and WESP for control. The Longleaf Energy project in Georgia, burning low-sulfur coal, has an emission rate of 0.005 lb/mmBtu (30-day average) using a dry scrubber and baghouse for control. This emission rate is lower than the August 2003 permit of 0.0061 lb/MMBtu for the Plum Point Project in Arkansas, and the March 2004 permit of 0.075lb/MMBtu for the Longview Power Project in West Virginia. The Roundup and Plum Point projects both use lower sulfur sub-bituminous coals as opposed to the range of eastern bituminous coals to be utilized at Cliffside.

Based on the above, DAQ has established a BACT limit for H_2SO_4 of 0.005 lb/mmBtu (3-hour average) using a SDA followed by a fabric filter. DAQ believes this rate is appropriate and achievable even though Cliffside will burn eastern bituminous high-sulfur coal. Since the controls proposed are considered the most stringent, no further analysis is made.

5.3.4 BACT Analysis for PC Boiler for Pb

Emissions of lead and other metals are generated in coal-fired boilers due to the inherent presence of inert mineral matter in coal (ash). Certain of these metals, such as lead may be vaporized within the high temperature combustion zone of the boiler. All such metals, however, re-condense, typically nucleating onto other small particles of flyash at the low temperatures of the air pollution control train. At operating temperatures of the proposed fabric filter, these metals exist as PM_{10} and are readily collected with filterable PM_{10}. Since the proposed units will employ BACT for PM_{10}, they will also employ BACT for lead and other trace metals.

Compliance with the filterable PM_{10} will be used to demonstrate compliance with BACT for non-mercury trace metals.

Pb BACT Determination for PC Boiler

Based on the above, DAQ has established a BACT limit for Pb of 0.000022 lb/mmBtu using a fabric filter.

5.3.5 BACT Analysis for PC Boiler for Visible Emissions

The US EPA recently issued revised New Source Performance Standards applicable to steam-electric generating units (40 CFR 60 Subpart Da) and industrial boilers (40 CFR 60 Subpart Db and Dc). These revised standards were issued after careful consideration of the achievable emissions for new or modified units equipped with the best control technologies commercially demonstrated. The revised NSPS reaffirmed a visible emissions standard of 20% opacity as measured on a 6-minute basis for electric generating units and industrial boilers. Duke is proposing a BACT limit of 20% 6-minute opacity for visible emissions for the proposed new Subpart Da electric generating unit and the Subpart Db auxiliary boiler.

5.3.6 BACT for PC Boiler During Startup and Shutdown

The proposed PC boiler will startup on low sulfur distillate oil up to the manufacturer's defined partial load to heat up the equipment. The mass emissions (lb/hr) from distillate oil firing at part load will always be less than allowable emissions from the boilers at full load firing coal. Once certain temperature and load parameters are met, coal is introduced into the boiler. The startup sequence will continue as equipment and operating parameters are brought to minimum stable operating conditions on coal (approximately 35% load). Pollution control equipment will be brought into service throughout the startup sequence in accordance with manufacturer recommendations to assure proper safety and operating performance of the equipment. The SDA, fabric filter and the wet FGD systems will be brought into service and will achieve substantial control once the coal is introduced to the boiler. However, these systems will not achieve optimum performance until steady state, stable load conditions are achieved. The SCR has a minimum operating temperature that corresponds closely with minimum load, and will not be brought into service until that load is reached. While individual emission rate factors will vary from limits established for normal operating conditions, all emissions from the proposed PC boiler will remain controlled to the extent feasible consistent with good design, operation, and maintenance. Startup emissions have been considered in the proposed BACT limits for each pollutant subject to continuous monitoring requirements by use of 30-day rolling average. Emissions are expected to fluctuate less during a planned shutdown sequence, as the boiler and emission control equipment will start at steady state conditions and the production of pollutants will essentially cease when fuel is removed from the boiler.

For startup/shutdown operations, Duke expects that the mass emissions occurring during the startup/shutdown period divided by the entire length of the startup/shutdown period will not exceed the mass emissions resulting from maximum heat input multiplied by proposed BACT emission limits. Duke therefore proposes that BACT for startup and shutdown of the PC boiler be the total duration of startup/shutdown multiplied by the maximum allowable mass emission rate in lb/hr (and specifically not the proposed BACT limits for normal operation in units of lb/mmBtu) for each BACT pollutant.

Excess emissions during startup and shutdown shall be considered a violation of 15A NCAC .0530 if the owner or operator cannot demonstrate that the excess emissions are unavoidable. To determine if excess emissions are unavoidable during startup or shutdown the DAQ shall consider the following along with any other pertinent information: (1) the air cleaning device, process equipment, or process has been maintained and operated, to the maximum extent practicable, consistent with good practice for minimizing emissions; (2) the amount and duration of the excess emissions, including any bypass, have been minimized to the maximum extent practicable; (3) all practical steps have been taken to minimize the impact of the excess emissions on ambient air quality; (4) the excess emissions are not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and (5) if the source is required to have a malfunction abatement plan, it has followed that plan. The DAQ may specify for a particular source the amount, time, and duration of emissions allowed during startup or shutdown. The owner or operator shall, to the extent practicable, operate the source and any associated air pollution control equipment or monitoring equipment in a manner consistent with best practicable air pollution control practices to minimize emissions during startup and shutdown.

5.4 BACT Analysis for Aux Boiler

The proposed auxiliary boiler is a 190 mmBtu/hr "package" boiler, fired with low sulfur (0.05% S) No. 2 distillate oil (except for propane for startup only). The auxiliary boiler will be used to provide steam for space heating, standby and startup needs when the proposed coal units are out of service; hence, Duke has proposed an enforceable operating restriction limiting operation of the auxiliary boiler to no more than 10% capacity factor, equivalent to full load operation for no more than 876 hours per year. Each of the main boilers is expected to have a base load annual capacity factor; therefore, operation of the auxiliary boiler should be infrequent.

The Duke Cliffside Project (and its proposed auxiliary package boiler) is subject to PSD review, including BACT, for PM_{10}, CO and VOCs.

A summary of the BACT emission limits and control technology for the auxiliary boiler is shown in Table 5-6.

Table 5-6
BACT Emission Limits and Control Technology Summary for Aux Boiler

POLLUTANT	BACT EMISSION LIMIT	CONTROL TECHNOLOGY
PM_{10}	0.014 lb/mmBtu heat input (filterable only) 0.024 lb/mmBtu heat input (filterable + condensable)	low ash fuel 10% capacity factor
carbon monoxide	0.036 lb/mmBtu heat input	good combustion control
VOCs	0.0024 lb/mmBtu heat input	good combustion control

5.4.1 BACT Analysis for Aux Boiler for PM_{10}

All distillate oil-fired boilers listed in EPA's RBLC use low ash fuels to limit emissions of PM_{10}. The Cliffside Generating Station does not have natural gas service. Back-up units such as the proposed auxiliary boilers require on-site fuel storage (pipeline natural gas is an interruptible fuel supply); the cleanest fuel available for this service, therefore is distillate oil, which contains essentially no ash. PM_{10} from the proposed auxiliary boiler will be further limited with a proposed use restriction of up to 876 hrs/yr. The proposed BACT limits for PM_{10} for the auxiliary boiler are based on EPA emission factors published in AP-42 for boilers utilizing low sulfur (0.05%) distillate oil. For PM_{10}, a BACT filterable emission limit of 0.014 lb/mmBtu is proposed based on the EPA emission factor of 2 lb/1000 gal. For total PM_{10} (front and back half) a BACT emission limit of 0.024 lb/mmBtu is proposed based on adding condensable PM_{10} emissions of 0.01 lb/mmBtu (1.3 lb/1,000 gal based on AP-42) to the filterable PM emission rate. These proposed emission rates are consistent with the data from EPA's RBLC, since the Clearinghouse data generally do not include condensable PM_{10}. No add-on particulate controls have been identified that would be technically feasible or applicable to distillate oil-fired boilers.

Summary of BACT for PM_{10} for Aux Boiler

Based on the above, DAQ concludes that the use of low ash distillate oil and limiting annual fuel use to a 10% capacity factor is determined to represent BACT for PM_{10} at an emission limit of 0.014 lb/mmBtu for filterable PM_{10} and 0.024 lb/mmBtu for total PM_{10} (front and back half) for the proposed auxiliary package boiler.

5.4.2 BACT Analysis for Aux Boiler for CO and VOCs

Emissions of CO and VOCs are both products of incomplete combustion (PICs) of the fuel. All CO and VOCs control techniques seek to more fully burn out these PICs with excess oxygen typically present. Oxidation catalysts have been routinely applied to combustion turbines (which exhibit much higher levels of PICs than steam boilers), however oxidation catalyst technology is not applicable to auxiliary package boilers. The oxidation catalyst must be placed within a section of the furnace where the flue gas temperature is consistently 800-1,000 degrees F. Further, the catalyst bed requires a large surface area (as in the full-height HRSG of a combined cycle turbine) to limit space velocity of the flue gases across the catalyst bed and to limit adverse pressure drop. Finally, the placement of a catalyst barrier within the furnace of a package boiler would increase risk of explosion in the event of flame out. The application of oxidation catalyst technology within the compact, load-following design of a package boiler is concluded to be not technically feasible. The next best level of control is achieved with good combustion control via time, temperature and turbulence. Today's generation of LNB seek to provide low NO_x profiles through staged combustion, while simultaneously adding back oxygen to effectively burn out CO and VOCs. This represents the top level of control for products of incomplete combustion from this source type.

Summary of BACT for CO and VOCs for Aux Boiler

The top level of control for this particular source type was determined to be the use of combustion controls to avoid incomplete combustion of CO and VOCs. What little CO and VOCs are emitted is a necessary side effect of simultaneously controlling NO_x to very low levels. The use of LNB designed for good combustion control for the proposed limited-use auxiliary boiler is therefore determined to represent BACT for CO at an emission rate of 0.036

lb/mmBtu and for VOCs at an emission rate of 0.0024 lb/mmBtu for the proposed distillate oil-fired auxiliary package boiler.

5.5 BACT Analysis for Cooling Tower

The multi-cell mechanically induced draft cooling tower will be a source of PM_{10} emissions which will be controlled by drift eliminators. Particulates are emitted from the escape of water droplets containing dissolved solids. A certain fraction of these droplets will be of a size range such that upon evaporation in the atmosphere, a resulting particle of PM_{10} could be liberated as an air emission. PM_{10} (all filterable) is controlled by drift eliminators, which limit the number and size distribution of liquid water droplets that escape the tower (called "drift"). Duke proposes to use state-of-the-art mist (drift) eliminators with a maximum drift rate equal to 0.0005% of the recirculated water flow to limit drift of water droplets that may contain dissolved solids (TDS) as BACT. There are no cooling towers identified in the RBLC with specified control other than drift eliminators.

5.6 BACT Analysis for Emergency Engines

The proposed project will be equipped with one 2350 hp diesel emergency generator and one 430 hp diesel engine driven emergency firewater pump. The emergency generator will be used only during an interruption of the electrical power supply to the site and for short test periods. Both sources will be operated for a maximum of 100 hours per year each (including for testing) in accordance with NSPS requirements and will fire 0.05% low sulfur, low ash distillate oil.

5.6.1 BACT for PM_{10} from Emergency Diesel Engines

PM_{10} emissions from the emergency diesel engines will be limited through the use of low sulfur, low ash fuel (0.05% sulfur distillate oil) and annual use limitations. Duke proposed BACT PM_{10} emission limits of 0.22 g/hp-hr and 0.19 g/hp-hr for PM_{10}, respectively, based on EPA emission factors in AP-42.

Since the BACT limits cannot be less stringent than the NSPS limits, as discussed in Section 4.1, DAQ has determined the BACT PM_{10} limit to be equivalent to the NSPS Subpart IIII limit as shown in Table 5-9 for each source based on manufacturers standard NSPS-compliant engine design and 100 hours maximum limited operation. Note, Subpart IIII did not become effective until September 11, 2006, which was after the time of submittal of the application in December 2005; therefore, these lower NSPS limits did not apply when the application was submitted.

Table 5-9
BACT Limits and Control Technology for Emergency Engines

AFFECTED SOURCE	POLLUTANT	BACT EMISSION LIMIT (g/hp-hr)	CONTROL TECHNOLOGY
emergency generator (ID No. ES-EG6)	nitrogen oxides + VOCs	4.8	low-NOx engine design 0.05% sulfur fuel oil good combustion control max. 100 hr/yr usage
	carbon monoxide	0.5	good combustion control max. 100 hr/yr usage
	PM_{10}	0.15	0.05% sulfur fuel oil max. 100 hr/yr usage
emergency firewater pump (ID No. ES-FWP)	nitrogen oxides + VOCs*	7.8 (2008 and earlier) 3.0 (2009 and later)	low-NOx engine design 0.05% sulfur fuel oil good combustion control max. 100 hr/yr usage
	carbon monoxide	0.5	good combustion control max. 100 hr/yr usage
	PM_{10}	0.40 (2008 and earlier) 0.15 (2009 and later)	0.05% sulfur fuel oil max. 100 hr/yr usage

5.6.2 BACT for CO from Emergency Diesel Engines

CO from the emergency diesel engines will be limited by good engine design and annual use limitations. Duke proposed a BACT CO emission limit for these diesel engines of 0.5 g/hp-hr based on vendor guarantees and data from engine manufacturers.

DAQ concurs with Duke's proposed BACT CO limit of 0.5 g/hp-hr as shown in Table 5-9.

5.6.3 BACT for VOCs from Emergency Diesel Engines

VOC from the emergency diesel engines will be limited by good engine design and annual use limitations. Duke proposed a BACT VOC emission limit for these diesel engines of 0.3 g/hp-hr based on EPA emission factors in AP-42.

DAQ concurs with Duke's proposed BACT VOC limit of 0.3 g/hp-hr and considers this limit to be built-in to the NSPS Subpart IIII NO_x limit as discussed in Section 5.6.1 above.

5.7 BACT Analysis for Material Handling (Coal, Lime and Ash)

Material handling sources including coal, ash and lime unloading, storage, reclaim, and loading are sources of both fugitive (area) and point source particulate emissions. In this case, all PM_{10} emissions are filterable only. In general, material handling system emissions will be controlled by wet or chemical dust suppression, enclosures or fabric filters as necessary. For example, water sprays, when needed, will be used to reduce fugitive dust at coal drops and, conveyors will be partially enclosed in order to control dust emissions due to wind, and fabric filters will be used to evacuate and control enclosed sources such as silos. BACT for the fabric filter controlled sources is proposed as a manufacturer's guarantee of 0.01 gr/dscf and annual maintenance performed to OEM specifications.

Section 3.0 and Appendix B of the application include a list of material handling emission sources and the proposed BACT emission control strategy for each. While emissions are estimated for sources other than the fabric filters, BACT for these sources constitutes equipment design, operating practices and in certain cases use limitations on redundant equipment. No numerical PM_{10} emission limits are proposed for these sources, although annual emissions will be calculated and reported based on the methodology used to estimate the materials handling emissions.

BACT Determination for Material Handling

DAQ searched the RBLC for the time period from 2001 to present, to identify current BACT determinations for PM_{10} for evaluating BACT for coal unloading, handling and storage, limestone unloading, handling, storage, and crushing, and ash handling. The following presents a summary of types of controls and/or emission limits established as BACT for PM_{10} for these types of equipment for recently issued PSD permits[10].

Coal handling and storage

- 0.005-0.01 grain/dscf with fabric filter
- 0.02 lb/ton of coal with high-efficiency fabric filter
- 5-20% opacity
- Other controls include water spray, lowering well, dust suppressants, and enclosures / partial enclosures, low-pressure drop and telescopic chutes

Lime storage

- 0.05 g/dscm with enclosures and filters
- 0.005-0.01 gr/dscf with fabric filter and scrubber
- 0.045 lb/ton of coal with high efficiency fabric filter
- 5-7% opacity

Ash handling and storage

- 0.005 gr/dscf with fabric filter
- 5% opacity

Haul Roads

- Water wash down, application of water or chemical stabilizers, daily inspection/cleaning/covering of transport vehicles

[10] Public Service of Colorado, RBLC ID CO-0057.
Newmont Nevada Energy Investment LLC, RBLC ID NV-0036.
Lamar Utilities Board DBA Lamar Light and Power, RBLC ID CO-0055.
Longview Power LLC, RBLC ID WV-0023.
Montana Dakota Utilities / Westmoreland Power, RBLC ID ND-0021.
Thouroughbred Generating Company LLC, RBLC ID KY-0084.

Separately, Duke reviewed recently issued PSD permits to Tucson Electric Springerville (AZ), Prairie State Generating (IL), Whelan Energy Center (NE), and Longview Power (WV) in order to obtain information about BACT for the above types of equipment. The following shows example BACT control techniques, which were approved for similar sources in these BACT decisions:

• Fabric filters exhausting coal transfer points	No opacity, 99% control, or 0.05 – 0.02 gr/DSCF
• Coal unloading operations	Windscreens with dust suppression
• Coal handling operations	Application of suppressants and coal throughput limits
• Coal conveyors	Full enclosure with dust suppression
• Truck dump to limestone feeder hopper	Partial enclosure with dust suppression
• Feeder transfer to bucket elevator	Full enclosure with dust suppression
• Belt transfer to Limestone pile	Partial enclosure with telescopic chute
• Reclaim conveyor to storage conveyor	Partial enclosure with dust suppression
• Silo drop	Full enclosure (the silo itself)
• Ball mill	Partial enclosure
• Haul roads for lime transport	Paving

Review of Applicable New Source Performance Standards

BACT for the proposed coal and limestone handling equipment cannot be less stringent than the applicable NSPS. Some of the proposed coal and limestone handling equipment are subject to NSPS Subpart Y and Subpart OOO respectively. These NSPS requirements have been summarized below:

- Point source (stack) emissions of particulate matter from non-metallic mineral processing plants are subject to the following limitations:

    A. The rate of emissions from point emission sources (such as bin vent filters) shall not exceed 0.022 gr/dscf (40 CFR 60.672 (a)(1)).
    B. The opacity of emissions from point emission sources shall not exceed 7 percent (40 CFR 60.672 (a)(2) and (f)).

- Fugitive source (non-stack) emissions of particulate matter from non-metallic mineral processing plants are subject to the following limitations:

    A. The opacity of emissions from belt conveyors, bucket elevators, grinding mills, screening operation, storage bins, and enclosed truck or railcar loading operations shall not exceed 10% (40 CFR 60.672(b)).
    B. The opacity of emissions from crushers shall not exceed 15% (40 CFR 60.672 (c)).
    C. Truck dumping into any screening operation, feed hopper, or crusher is exempt from the above standards (40 CFR 60.672 (d)).

- Point source (stack) and fugitive emissions of particulate matter from coal preparation plants are subject to the following limitations:

A. The opacity of emissions from coal processing and conveying equipment, coal storage systems (excluding open storage piles), and coal loading systems shall not exceed 20 percent (40 CFR 60.252(c)).

Summary of BACT for Material Handling

DAQ proposes the BACT limits and control technology for PM10 emissions for the material handling sources as shown in Table 5-10.

Table 5-10
BACT Limits and Control Technology for Material Handling

EMISSION SOURCE	POLLUTANT	BACT EMISSION LIMITS	CONTROL TECHNOLOGY
One railcar coal unloading station and two unloading hoppers (ID No. C-1)	PM_{10}	20 percent opacity [6-minute average]	partially covered building and dust suppression (water or chemical)
Two belt feeders (ID Nos. BF-1 and BF-2)	PM_{10}	20 percent opacity [6-minute average]	underground
Three coal stockout conveyors (ID Nos. C-2, C-3, and C-4)	PM_{10}	20 percent opacity [6-minute average]	partial enclosure and dust suppression (water or chemical)
Two coal telescoping chutes (ID Nos. C-5 and C-7)	PM_{10}	20 percent opacity [6-minute average]	dust suppression (water or chemical)
Coal storage pile fugitives (ID Nos. C-9 and C-10)	PM_{10}	none	good pile management and dust suppression (water or chemical)
Coal bulldozing (ID No. C-11)	PM_{10}	none	dressing of working pile
Coal reclaim hoppers (ID No. C-12)	PM_{10}	20 percent opacity [6-minute average]	underground
Eight reclaim feeders (ID Nos. VF-51 through VF-58)	PM_{10}	20 percent opacity [6-minute average]	underground
One coal crusher house (ID No. C-15)	PM_{10}	20 percent opacity [6-minute average]	dust extraction system, partial enclosure for conveyor and enclosed building for crusher house
One railcar limestone unloading station (ID No. LS-1)	PM_{10}	20 percent opacity [6-minute average]	partially covered building and dust suppression (water or chemical)
Two limestone unloading hoppers (ID No. LS-1A and LS-1B)	PM_{10}	10 percent opacity [6-minute average]	partially covered building and dust suppression (water or chemical)
Two belt feeders (ID Nos. BF-3 and BF-4)	PM_{10}	10 percent opacity [6-minute average]	underground
One limestone stockout conveyor (ID No. LS-2)	PM_{10}	10 percent opacity [6-minute average]	partial enclosure and covered building
One limestone stockout conveyor (ID No. LS-6)	PM_{10}	10 percent opacity [6-minute average]	partial enclosure and dust suppression (water or chemical)

EMISSION SOURCE	POLLUTANT	BACT EMISSION LIMITS	CONTROL TECHNOLOGY
One limestone storage pile (ID No. LS-8)	PM_{10}	none	good pile management and dust suppression (water or chemical)
Limestone bulldozing (ID No. LS-9)	PM_{10}	none	dressing of working pile
Limestone reclaim hoppers (ID Nos.LS-10)	PM_{10}	10 percent opacity [6-minute average]	underground
Two limestone reclaim feeders (ID Nos. VF-40 and VF-41)	PM_{10}	10 percent opacity [6-minute average]	underground
One limestone reclaim conveyor (ID No. LS-11) and two limestone silos (ID Nos. LS13-1, and LS13-2)	PM_{10}	0.01 grain/dscf (filterable only) for both PM and PM_{10} [3-hr average], and 7 percent opacity [6-minute average]	baghouse, partially underground and partial enclosures for conveyors
Two limestone ball mills (ID Nos. LSBM-1 and LSBM-2)	PM_{10}	15 percent opacity [6-minute average]	total enclosure
Two gypsum stockout conveyors (ID Nos. GS-3 and GS-4)	PM_{10}	20 percent opacity [6-minute average]	none
Gypsum truck loading (ID No. GS-9)	PM_{10}	20 percent opacity [6-minute average]	none
One gypsum storage pile (ID No. GS-5)	PM_{10}	none	good pile management and dust suppression (water or chemical)
Landfill for ash and gypsum (ID No. Landfill)	PM_{10}	none	good pile management and dust suppression (water or chemical)
Emergency quench water pump (ID No. QP5)	PM_{10}	0.2 gram/kW-hr (filterable only) [3-hr average]	none
U6 Coal Reclaim Hoppers (ID No. ES-C19)	PM_{10}	20 percent opacity [6-minute average]	underground
Coal Reclaim Feeders for Unit 6 (ID Nos. ES-VF1 thru ES-VF8)	PM_{10}	20 percent opacity [6-minute average]	underground
Coal Reclaim Conveyor RC11 to U6 Boiler Building (ID No. ES-C27), Coal Reclaim Conveyor RC12 to U6 Boiler Building (ID No. ES-C28), Unit 6 Tripper Conveyor TR2 (ID No. ES-C29), and Unit 6 Tripper Conveyor TR3 (ID No. ES-C30)	PM_{10}	0.01 grain/dscf (filterable only) for both PM and PM_{10} [3-hr average], and 20 percent opacity [6-minute average]	baghouse, partial enclosures and enclosed buildings

EMISSION SOURCE	POLLUTANT	BACT EMISSION LIMITS	CONTROL TECHNOLOGY
Two Dry Fly Ash Pickups at Boiler Economizer (ID Nos. ES-A3 and ES-A8), Dry Fly Ash Pickup at Bagfilter (ID No. ES-A9), Dry Fly Ash Silo (ID No. ES-A6), and Dry Fly Ash Truck Loading (ID No. ES-A7)	PM_{10}	0.01 grain/dscf (filterable only) for both PM and PM_{10} [3-hr average], and 20 percent opacity [6-minute average]	baghouse
Dry Fly Ash discharge to truck (ID No. ES-A12)	PM_{10}	20 percent opacity [6-minute average]	dust suppression (water or chemical)
Lime Silo for SDA (ID No. ES-LSSDA)	PM_{10}	0.01 grain/dscf (filterable only) for both PM and PM_{10} [3-hr average], and 20 percent opacity [6-minute average]	baghouse
Facility haul roads (ID No. FVehicle)	PM_{10}	none	dust suppression (water or chemical)

SECTION 6

AIR QUALITY IMPACT ANALYSIS

PSD regulations (40 CFR 51.166 (k)) require an applicant to perform an ambient impact analysis to determine if the Class II Area National Ambient Air Quality Standards (NAAQS), Class II Area increment, and Class I Area increment standards will be exceeded at any location and during any time period where the proposed new source will have significant impact.

In addition, PSD regulations require that for a contemporaneous decrease in actual emissions (as part of netting for SO_2 and NO_X) to be creditable, it must have approximately the same qualitative significance for public health and welfare as that attributed to the increase from the modification (see Section 6.2 below). Also, North Carolina toxic standards for ammonia and sulfuric acid (see Section 6.3) and State Ambient Air Quality Standards (SAAQS) for TSP (see Section 6.3) must not be exceeded.

This modeling review addresses TSP/PM_{10}, CO, lead, sulfuric acid and ammonia impacts. The modeling analysis shows that this facility will not cause or contribute to an exceedence, on a source-by-source basis, to the Class II NAAQS and PSD Increment, Class I Increment, state regulated total particulate emission (TSP) SAAQS or any NC air toxic Acceptable Ambient Levels (AALs). The modeling also indicates that this facility will have no impact on Air Quality Related Values (AQRVs) for any Class I area within the state.

The Cliffside facility is located near the border of rural Rutherford land Cleveland counties on the banks of the Broad River in the Southwestern Piedmont of North Carolina. The area of the proposed facility is dominated by agricultural and forest land use types and is characterized by gently rolling terrain, with elevations ranging from 230 to 350 meters above mean sea level (MSL). The area is classified rural based on the land use type scheme established by Auer 1978. Rutherford and Cleveland counties are designated attainment for the respective NAAQS pollutants.

A summary of projected sources netting analysis and tons per year (TPY) emission rates is shown in Table 4-4. The netting analysis shows that Particulate Matter (PM_{10}), Carbon Monoxide (CO) and Lead (Pb) will require a Class II NAAQS and PSD Increment analysis**.**

6.1 NAAQS/PSD Increment Air Dispersion Modeling Analysis

6.1.1 Preliminary Impact Analysis

Duke Energy conducted the required air quality impact analysis using the latest version of the EPA approved AERMOD model (04300). The modeling was accomplished in two phases. In phase one, a preliminary impact analysis was performed to determine the load condition (e.g., 100%, 75%, or 50%) that resulted in the highest impacts and to identify the pollutants that exceeded the Class II Significant Impact Levels (SILs). In phase II, any pollutant found to exceed the Class II SILs is required to undergo a full impact air quality analysis (section 6.1.1.2). The full impact analysis incorporates all remaining onsite source emissions, offsite source emissions, and background concentrations. The preliminary impact analysis was also used to define the pollutant specific impact area and help establish the offsite emission inventory.

The AERMOD model was run using five years (1987-1991) of Charlotte surface and Greensboro upper-air meteorological data. The AERMOD model uses land use characteristics at the meteorological site and evaluates for all terrain conditions. The land use for 3 kilometers around the site was characterized by three different sectors based on distinctly different land use (e.g. urban, industrial and rural) and was further broken down for seasonal variations. All source heights were determined to be less than their respective GEP stack height calculations; subsequently, building wake effects were considered by using the latest version of the EPA approved BPIP-PRIME to develop 36 direction specific building dimensions for each point source modeled. As appropriate, AERMOD will also calculate building cavity impacts.

To determine the location of maximum concentration a Cartesian receptor grid system was employed. The receptor grid, consisting of over 1200 receptors, extended from the facility fence-line at 50-meter intervals out to 500 meters. Additional receptors were placed at 100-meter intervals from 500-meters to 1 kilometer and at 500-meter spacing from 1 to 5 kilometers.

The preliminary impact analysis results are shown in Table 6.1.1-1 and indicate that PM_{10} would exceed the SILs and require a full impact analysis to determine compliance with the NAAQS and PSD Increment. Note: a SIL has not been established for lead.

Table 6.1.1-1 Preliminary Impact Analysis

Pollutant	Averaging Period	Maximum Impacts ($\mu g/m^3$)	Class II SILs ($\mu g/m^3$)	% of the Class II SILs
PM_{10}	24-Hour Annual	15.53 5.97	5 1	310 597
CO	1-hour 8-hour	130.16 53.91	2000 500	6.5 10.8

6.1.2 Full Impact Analysis

Using the model and modeling methodology described in section 6.1.1, Duke Energy conducted a full impact air quality analysis for both PM_{10} and lead to determine compliance with the appropriate NAAQS and PSD increment. All applicable NAAQS and PSD increment onsite emissions and offsite source emissions (within 60 km) were included in the analysis which also included the appropriate background concentration (Gaston Co., NC / Spartanburg Co., SC) for PM_{10} (NAAQS). Tables 6.1.2-1 and 6.1.2-2 summarize the modeled results and indicate compliance with the applicable pollutant NAAQS and PSD increment.

Table 6.1.2-1 Class II NAAQS Analysis

Pollutant	Averaging Period	Modeled Impact[1] (μg/m³)	Background (μg/m³)	Total Impact (μg/m³)	NAAQS (μg/m³)	% of NAAQS
PM_{10}	24-hour	72.93	30	102.93	150	68.6
	Annual	15.82	19	34.82	50	69.6
Lead	Quarterly	0.0024	NA[2]	0.0024	1.5	0.2

1 Includes all onsite and appropriate offsite sources.
2 North Carolina does not monitor for lead.

Table 6.1.2-2 PSD Class II Increment Analysis

Pollutant	Averaging Period	Modeled Impact[1] (μg/m³)	Increment (μg/m³)	% of Increment
PM_{10}	24-hour	14.39	30	48
	Annual	6.02	17	35.4

1 Includes all onsite and offsite increment consuming sources.

6.2 SO_2 and NO_x Ambient Impacts

DAQ also requested Duke Energy to conduct additional SO_2 and NO_x modeling to ensure that the future facility source configuration will not show increased environmental impacts. This addresses the PSD requirement under 51.166(b)(3)(vi)(*c*), as discussed on page 11 that, for a contemporaneous decrease in actual emissions (as part of netting) to be creditable, it must have approximately the same qualitative significance for public health and welfare as that attributed to the increase from the modification. This applies to SO_2 and NO_X emissions for which Duke netted out of PSD for the modification. Duke has demonstrated this requirement by showing that the ambient impacts will be lower after the modification. Note: the existing configuration of Units 1-5 was previously modeled in compliance. The additional modeling requested used the same model and modeling methodology described in section 6.1.1 to compare the off property impacts of the existing and future (Units 5 and 6) configurations. Table 6.2-1 summarizes the modeled results and shows a considerable reduced impact with the new configuration.

Table 6.2-1 Existing / Future Configuration Analysis

Pollutant	Averaging Period	Existing (Units 1-5) Impacts (µg/m³)	Future (Units 5 & 6) Impacts (µg/m³)	Difference (µg/m³)	% Decrease
SO_2	3-hour	882.8[1]	318.66[2]	564.14	63.9
	24-hour	336.3[1]	115.28[2]	221.02	65.7
	Annual	75.2[1]	16.21[2]	58.99	78.4
NO_x	Annual	15.77[2]	2.00[2]	13.77	87.3

1 From Table 4 in Section 8 of Cliffside Units 1-4 Stack Height Extension Project or from e-mail to Ed Martin from Jeffrey Connors dated December 1, 2006

2 From Updated Class II Modeling dated June 11, 2007

6.3 Non Regulated Pollutant Impact Analysis

Total Suspended Particulate (TSP) is a North Carolina regulated pollutant and was evaluated with respect to the State Ambient Air Quality Standards (SAAQS). Also, as part of the Best Available Control Technology (BACT) analysis, DAQ requested that Duke evaluate ammonia and sulfuric acid against the North Carolina Toxics Program. The model and modeling methodology described in section 6.1.1 was also used to determine compliance for TSP and for the North Carolina air toxics, ammonia and sulfuric acid. Table 6.3-1 summarizes the modeled results and indicates compliance with the applicable TSP SAAQS and air toxic AALs. Note, North Carolina Toxic impacts do not consider or monitor background concentrations.

Table 6.3-1 TSP / NC Air Toxics Analysis

Pollutant	Averaging Period	Modeled Impact (µg/m³)	Background (µg/m³)	Total Impact (µg/m³)	SAAQS (µg/m³)	AAL (µg/m³)	% of the NAAQS / AAL
TSP	24-hr	73.46	64	137.5	150		91.6
	Annual	30.31	30	60.3	75		80.4
Ammonia	1-hour	1.2	n/a[1]	1.2		2700	<1
Sulfuric Acid	1-hour	1.8	n/a[1]	1.8		100	1.8
	24-hour	0.6	n/a[1]	0.6		12	5

1 Background concentrations are not used in evaluating North Carolina Toxic impacts.

6.4 Additional Impact Analysis

PSD regulations [40 CFR 51.166 (o)] and the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Report requires an applicant to provide information to determine if the proposed source would have an adverse impact on growth, soils, vegetation, regional visibility, and any Federal Class I area AQRVs.

6.4.1 Growth Impacts

A growth analysis includes the projection of the associated industrial, commercial, and residential source emissions that will occur in the area due to the source. This is accomplished by evaluating issues such as the increase in local work force and assessing secondary emission sources that potentially will build in the area to support the Duke Energy operations. The proposed project is not expected to significantly increase labor requirements and will not result in the creation of many new jobs. The project is not expected to increase plant personnel traffic or housing demands in the area or significantly increase truck traffic. Anticipated secondary emissions associated with the project are negligible.

6.4.2 Soils and Vegetation

The analysis was based on an inventory of the soils and vegetation types found in the impact area and included all vegetation with any commercial or recreational value. Numerous resources such as conservation groups, state agencies, and universities were used to determine the inventory.

The facility is located in the western Piedmont area of North Carolina. The local geography is characterized by gently rolling terrain with mixed land use such as farming, open grasslands and forest. The crop types within the local area include corn, wheat, soybeans, cotton and alfalfa. Vegetation other then crops include several grasses and trees such as longleaf-slash pine, loblolly-shortleaf pine, mixed oak-pine and oak-hickory, hickory, black gum, elm, ash and other hardwood trees.

Effects of airborne emissions on soils are considered important due to the relationships that exist between soils, ground and surface waters, and vegetation; however, since the expected impacts from the facility are below both the NAAQS and PSD increment standards, adverse effects to soils and vegetation are not expected.

6.4.3 Class II Visibility Impairment Analysis

The Class II visibility impairment analysis is distinct from the Class I impact in that it is concerned with visibility within the surrounding area (impact region) of the proposed new source or modification. This analysis is accomplished by initially using a conservative screening tool to assess the possibility of visibility impairment based on expected emissions.

Duke Energy needed only to assess visibility within their impact area but chose to look beyond the impact area (out to 50 kilometers). This assessment used the EPA VISCREEN (version 1.1) model to determine the furthest distance to which a plume from the facility might be visible. A level I VISCREEN analysis was accomplished as discussed in Section D of the New Source Review Workshop Manual, Draft 1990. Duke Energy used particulate (PM), with background ozone values and a background visual range value of 80 kilometers, to determine impacts within this region.

The VISCREEN modeled results determined that no additional local visibility impairment would result as a result of this project. Since there are no scenic vistas or byways; national historic parks, battlefields, monuments, parks or memorials within that distance, no further analysis is required.

6.5 Class I Increment and Air Quality Related Values (AQRV) Regional Haze Impact Analysis

6.5.1 Class I Increment Impact Analysis

The Class I modeling analysis was conducted to determine if there was a significant impact to all identified Class I area locations (see map at end of this section). As identified in the EPA IWAQM Phase II report and the Federal Land Managers AQRV Phase I report (FLAG), the CALPUFF modeling system is the preferred air dispersion model for evaluating long-range transport of NO_x, SO_2 and PM_{10} emissions and was used in this analysis. Tables 1 and 2 of the March 26, 2007, submittal and analysis list the emissions and source parameters used in the analysis.

Two receptor grids were modeled using three years (2001-2003) of MM5 meteorological data. The first receptor grid was centered on the facility and extended outwards to 50 kilometers. Additional receptors were modeled at each of the Class I areas to determine the highest Class I impacts. Table 6.5.1-1 below, shows that the facility will not exceed the Class I SILs and thus no further modeling is required.

Table 6.5.1-1 Class I Increment Analysis

Pollutant	Class I Area ($\mu g/m^3$)	Maximum Impact ($\mu g/m^3$)		Class I SILs ($\mu g/m^3$)		% of SILs	
		Avg Period		Avg Period		Avg Period	
		24-hr	Annual	24-hr	Annual	24-hr	Annual
PM_{10}	Cohutta	0.0739	0.0026	0.32	0.16	23	1.6
	Great Smokey Mt.	0.1371	0.0026	0.32	0.16	43	1.6
	Joyce Kilmer- Slickrock	0.0995	0.0022	0.32	0.16	31	1.4
	Linville Gorge	0.1215	0.0068	0.32	0.16	38	4.3
	Shinning Rock	0.1434	0.0040	0.32	0.16	45	2.5

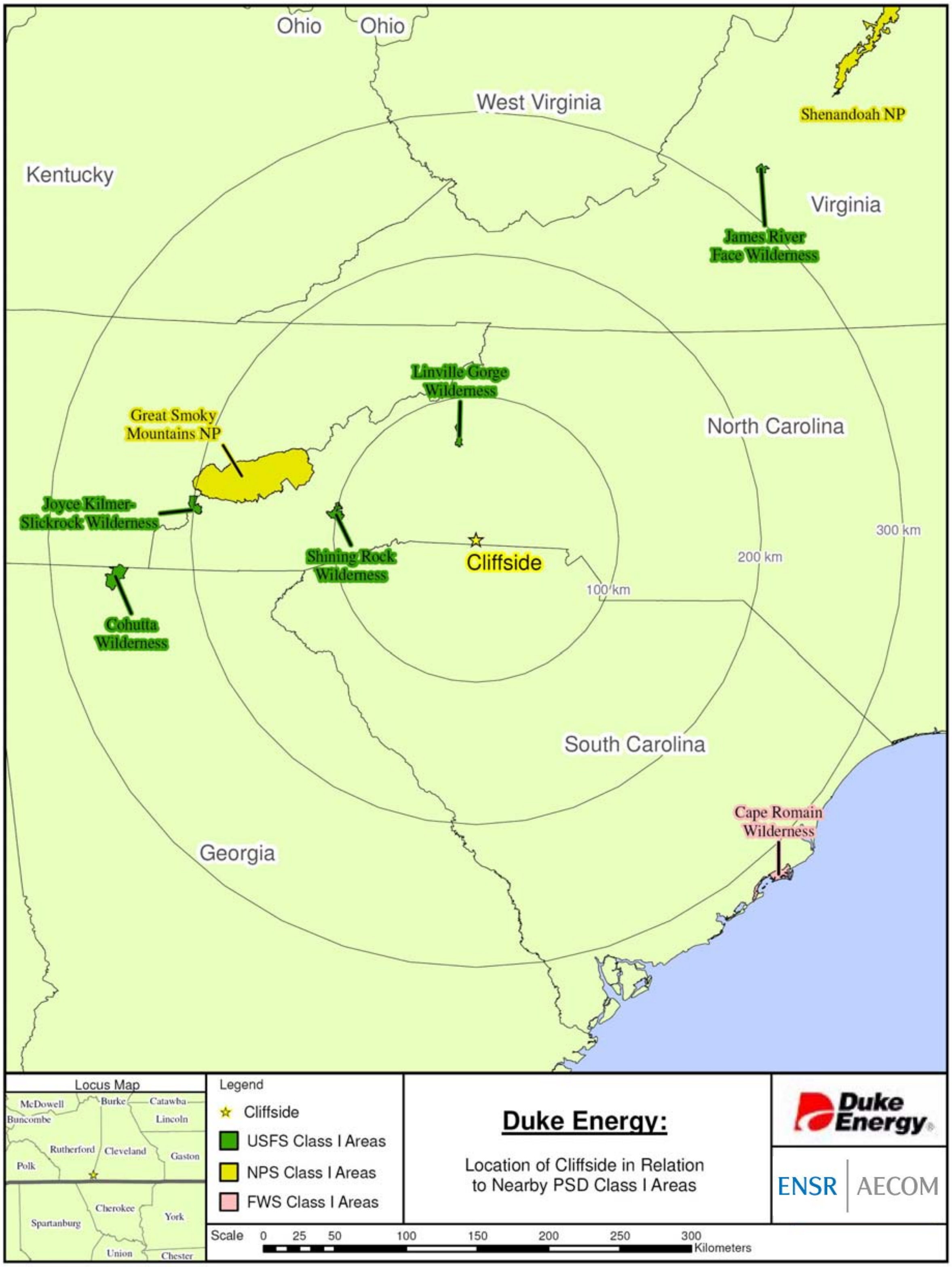
6.5.2 Class I Air Quality Related Value (AQRV) Regional Haze Impact Analysis

The Class I area regional haze and deposition modeling analysis was conducted to ensure impacts at all Class I areas would not exceed established visibility thresholds. The analysis was consistent with most of the requirements identified in the IWAQM Phase II and FLAG reports and DAQ's protocol comments dated September 1, 2005**.** Note: the differences between the FLM Flag document recommendations and the DAQ approved modifications are discussed in the April 2007 Class I report and analysis.

The CALPUFF modeling system is the preferred air dispersion model for assessing long-range transport of PM_{10} emissions and was used to evaluate regional haze impacts at five Class I areas within 300 km of the Cliffside facility. The analysis incorporated three years (2001-2003) of MM5 prognostic meteorological data along with meteorological data from numerous National Weather Service (NWS) stations and precipitation monitoring stations within the modeling domain. Maximum potential emission rates of PM_{10} (provided in Table 10-1 of the modeling report) from each generating unit were modeled at both 50% and 100% load scenarios. Impacts of PM_{10} at the Class I areas were used in CALPUFF's post-processor, CALPOST, to determine changes in extinction threshold. The modeling indicated maximum visibility impacts would be less than 1% at all Class I areas and, therefore, will not exceed 5% change in extinction threshold for any days at any of the Class I areas.

6.6 Source Impact Analysis Conclusion

Based on the ambient impact analysis, the proposed modifications to the Duke Energy Cliffside facility will not cause or contribute to any violation of the Class II NAAQS, Class II increments, Class I increments, NC toxic AALs, or Class II AQRVs.


Ohio
Ohio
West Virginia
Kentucky
Virginia
Shenandoah NP
James River
Face Wilderness
Linville Gorge
Wilderness
North Carolina
Great Smoky
Mountains NP
Joyce Kilmer-
Slickrock Wilderness
Shining Rock
Wilderness
Cliffside
100 km
200 km
300 km
Cohutta
Wilderness
South Carolina
Cape Romain
Wilderness
Georgia
Locus Map
McDowell
Burke
Catawba
Buncombe
Lincoln
Rutherford
Cleveland
Gaston
Polk
Cherokee
Spartanburg
York
Union
Chester
Legend
Cliffside
USFS Class I Areas
NPS Class I Areas
FWS Class I Areas
Duke Energy:
Location of Cliffside in Relation
to Nearby PSD Class I Areas
Duke Energy
ENSR | AECOM
Scale 0 25 50 100 150 200 250 300 Kilometers

APPENDIX A

Draft Permit

APPENDIX B

Public Notice

APPENDIX C

Correspondence

Date/Subject	Addressed To	From
March 2, 2006 (on website) Additional Information on NSPS	Ed Martin NCDAQ	Albert J. Smith Duke Energy
October 30, 2006 (on website) Addendum to Class I Modeling	Ed Martin NCDAQ	Jeffrey Connors ENSR
November 20, 2006 (on website) Revised Submittal on PM10 BACT Analysis	Dr. Don van der Vaart, P.E. NCDAQ	Rick R. Roper Duke Energy
December 1, 2006 (on website) Additional Modeling Analysis and BACT for VE	Dr. Don van der Vaart, P.E. NCDAQ	Rick R. Roper Duke Energy
December 1, 2006 e-mail Cliffside Modeling	Ed Martin NCDAQ	Jeffrey Connors ENSR
December 21, 2006 (on website) Mercury Emission Limits	Dr. Don van der Vaart, P.E. NCDAQ	Rick R. Roper Duke Energy
March 7, 2007 (on website) Revised Application to Delete Second Unit	Don van der Vaart NCDAQ	Rick R. Roper Duke Energy
March 26, 2007 (on website) Addendum to Class I Modeling	Rick Roper Duke Energy	Jeffery Connors ENSR
April 18, 2007 (on website) containing the following:		
April 9, 2007 Update SO_2 Netting Analysis – Based on 1 Unit	Rick Roper Duke Energy	Jeffery Connors ENSR
April 9, 2007 Update NO_X Netting Analysis – Based on 1 Unit	Rick Roper Duke Energy	Jeffery Connors ENSR
April 11, 2007 Addendum to Class II Modeling	Rick Roper Duke Energy	Jeffrey Connors ENSR
April 11, 2007 Updated Netting Analysis	Rick Roper Duke Energy	Jeffrey Connors ENSR
May 8, 2007 (on website) Revised Control Technology and Site Layout	Don van der Vaart NCDAQ	Rick R. Roper Duke Energy
June 11, 2007 (on website) Updated Class II Modeling	Don van der Vaart NCDAQ	Rick R. Roper Duke Energy
June 13, 2007 (on website) PSD Application – Corrected Application Forms	Don van der Vaart NCDAQ	Rick R. Roper Duke Energy
July 6, 2007 e-mail Updated Class II NAAQS PM10 & TSP Modeling	Chuck Buckler NCDAQ	Jeffrey Connors ENSR

APPENDIX D

Previous BACT Determinations

RBLC Data (2001-2007) Summary for Pulverized Coal-Fired Utility Boilers for PM_{10}

RBLC Data (2001-2007) Summary for Pulverized Coal-Fired Utility Boilers for CO

RBLC Data (2001-2007) Summary for Pulverized Coal-Fired Utility Boilers for VOC

APPENDIX E

Application

Application dated December 16, 2005	(previously sent)	(on website)
July 2006 Addendum	(previously sent)	(on website)
October 2006 Addendum	(previously sent)	(on website)
August 24, 2006 Addendum	(previously sent)	(on website)
March 2007 Addendum	(previously sent)	(on website)
May 29, 2007 Addendum	(previously sent)	(on website)

APPENDIX F

Analysis of Integrated Gasification Combined Cycle

Analysis of Integrated Gasification Combined Cycle

Whether, and to what extent Integrated Gasification Combined Cycle (IGCC) should be considered in the BACT process has been an issue in most of the coal-fired projects proposed throughout the country in recent years. Some of the major issues include: (1) whether or not the application of IGCC to a coal-fired project would "redefine the source", (2) the technical feasibility of IGCC, both in terms of "availability" and "applicability", and (3) the economic impacts of IGCC.

As a threshold matter, the EPA and the Division of Air Quality (DAQ) have not required a BACT analysis to include technologies that would "redefine the source" proposed by the applicant[11]. Technologies that "redefine the source" include those that fundamentally change the nature of the project.

At least six state air quality agencies have decided that IGCC, as applied to recent proposals for coal-fired units, would redefine the source.[12] Two other state agencies (Illinois and New Mexico) have reached a different conclusion and required consideration of IGCC in a BACT analysis for a coal-fired power plant. No state air quality program has required IGCC for a coal-fired generating unit of any size as a result of a BACT process.

In 2005 EPA issued a letter advising one air quality permitting consultant that "applying the IGCC technology would fundamentally change the scope of the project and redefine the basic design of the proposed source.[13]" The issuance of this letter was litigated and ultimately led to a settlement agreement between EPA and other interested parties. As a result the EPA has recently initiated the Advanced Coal Technology (ACT) workgroup[14] to address, among other issues, IGCC and associated BACT technologies. After the workgroup has completed its analysis and published its findings, the DAQ will examine the findings and consider any implications for DAQ review of future applications of this type.

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[11] See e.g. In Re Knauf Fiber Glass, GMBH, 8 E.A.D. 121, 140 (EAB 1998); In the Matter of Old Dominion Cooperative, Virginia, 3 E.A.D. 779 (Adm'r 1992); In the Matter of Pennsauken County, New Jersey Resource Recovery Facility, 2 E.A.D. 667 (Adm'r 1988).

[12] Those states which determined that IGCC is redefining the source include Kentucky (see Thoroughbred Generating); Wisconsin (See Elm Road Generating, Case No. IH-04-03); Montana (see Bull Mountain); Georgia (See Longleaf Energy Plant); Missouri (See KCPL Iatan); Florida (see Seminole Generating Station Unit 3); and Utah (See Intermountain Power).

[13] Letter from Stephen D. Page, Director, EPA Office of Air Quality, Planning and Standards, to Paul Plath, Senior Partner, E3 Consulting, LLC (Dec. 13, 2005).

[14] The Advanced Coal Technology Work Group is being convened under the auspices of the Sub-Committee on Economic Incentives and Regulatory Innovation of the Clean Air Act Advisory Committee (CAAAC) and as part of a settlement between EPA and certain environmental groups relative to the Steve Page letter on IGCC dated December 13, 2005. Ben Henneke and Anna Wood (EPA/OPAR) are the Co-Chairs for the Work Group. The charge to the ACT work group is to discuss and identify the potential barriers and potential opportunities to create incentives under the CAA to the development and deployment of advanced coal technologies. The workgroup will be convened for a one-year time period. The initial time frame for the work group is January 2007 through January 2008.

Even if IGCC were deemed not to redefine the source in the context of a supercritical coal-fired unit, IGCC must still be a "technically feasible" control alternative to be included in the list of technologies addressed in the BACT analysis. In order to be technically feasible, IGCC must be both "available" and "applicable" to the proposed source.

With respect to availability, there are currently no IGCC plants the size (800 MW each) of the proposed supercritical pulverized coal (SCPC) boilers. According to EPA[15] "There are currently two commercial-scale, coal-based IGCC plants in the U.S. and two in Europe." The two U.S units are the 262 MW Wabash River, Indiana IGCC, and the 250 MW Polk Power Station IGCC in Florida. Both of the U.S. projects are part of DOE's Clean Coal demonstration programs[16] and therefore neither project can be considered a demonstrated commercially available technology.

Reliability is a key issue in building large base-load electric generating units. Concerns about the reliability of IGCC at its current state of development raise significant questions about use of IGCC for base-load electric power generation. EPA has concluded that: "Development and implementation of the IGCC technology is relatively immature compared with the PC technology that has hundreds or thousands of units in operation globally. While there are a number of gasification units installed at petroleum and chemical plants, there are only a few installations using coal to make electric power as the primary product. Most of these IGCC installations were installed with government subsidies and have experienced technical and commercial problems common to the startup of new technologies. While many of the problems with operability and maintainability have been mitigated, successful application of the IGCC technology at additional commercial installations is needed to address any remaining concerns."[17]

EPA goes on to note that "it is expected that the future commercial facilities, designed with a spare gasifier train, would achieve availability levels of 85 percent and higher. In comparison, the subcritical and supercritical PC can generally achieve greater than 90 percent availability levels".[18] In other words, even with projected increases in reliability, IGCC would still be less reliable than pulverized coal facilities. Any consideration of an IGCC as a replacement for a traditional PC-coal project must account for the differences in reliability when the project is intended to provide for base load electric generation.

Even if IGCC were considered "available" there is no evidence that this technology is "applicable" for an 800 MW unit. As noted above, there is a dearth of technical experience in building and operating an IGCC unit for base load operation. The DAQ is not aware of any

[15] "Final Report Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies" EPA-430-06/006 July 2006 p. 2-6

[16] The Wabash River project is funded jointly by the DOE (50%) and a consortium (50%), and is under the DOE CCPI/Clean Coal Demonstrations program (http://www.netl.doe.gov/technologies/coalpower/cctc/summaries/wabsh/wabashrdemo.html). The Polk IGCC project is part of the DOE's Clean Coal Technology Demonstration Program Advanced Electric Power Generation Integrated Gasification Combined-Cycle, and is funded by 49% by the DOE and 51% by a consortium (http://www.netl.doe.gov/technologies/coalpower/cctc/summaries/tampa/tampaedemo.html).

[17] IBID p ES-1

[18] IBID p. ES-5

vendor guarantees that could be relied upon to support identification of IGCC is an applicable technology for an 800 MW base load unit.

In summary, neither EPA nor any state air quality program has determined that IGCC is BACT for a coal-fired electric generating unit of any size. Both EPA and the majority of states that have considered the issue concluded that IGCC does not need to be considered in a BACT analysis for this type of unit. At this time, the NCDAQ concludes that IGCC is not a BACT candidate for this project based on significant uncertainty about the availability and applicability of the technology for base-load electric power generation at an 800-MW unit. NCDAQ will continue to evaluate the technology as it develops and is applied more broadly to electric power generation.