Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

August 2009

Facility Name: Plant Washington
City: Sandersville
County: Washington
AIRS Number: 04-13- 30300051
Application Number: 17924
Date Application Received: January 17, 2008

Review Conducted by:
State of Georgia - Department of Natural Resources
Environmental Protection Division - Air Protection Branch
Stationary Source Permitting Program

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Plant Washington for a permit to construct and operate a supercritical pulverized coal fired power plant rated at 850 MW net output capacity. The facility will be designed to include: one supercritical pulverized coal-fired 8,300 MMBtu/hr boiler; one ultra low sulfur diesel-fired 240 MMBtu/hr auxiliary boiler; a steam turbine and associated generator; thirty-four cell cooling tower; emergency diesel-fired generator; fire water pump; facilities for receiving, handling and storing of coal, anhydrous ammonia, limestone, mercury removal sorbent and sulfur trioxide removal sorbent; facilities for handling and storing of process byproducts; facilities for on-site storage of process waste; diesel fuel oil storage tanks; and supporting plant equipment. The facility will be designed to burn sub-bituminous coal (Powder River Basin, or PRB coal) or up to a 50/50 blend (by weight) of eastern bituminous coal (Illinois #6) and sub-bituminous coal. Although the facility will be designed for use of PRB and Illinois #6 coals, the facility will also have the capability of utilizing bituminous and sub-bituminous coals with equivalent characteristics of PRB and Illinois #6.

The construction of Plant Washington will result in emissions of Nitrogen Oxides (NOx), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), Particulate Matter (PM), Particulate Matter with an aerodynamic size equal to or less than ten microns (PM_{10}), Particulate Matter with an aerodynamic size equal to or less than 2.5 microns ($PM_{2.5}$), Volatile Organic Compound (VOC), Sulfuric Acid Mist (H_2SO_4), Fluorides (as HF) and Lead (Pb). The facility will emit more than 100 tons per year (tpy) of NOx, SO_2, CO, PM, PM_{10}, $PM_{2.5}$ and VOC and therefore, the facility is a major source under the PSD program since it is one of the 28 industrial categories (fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input). A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any increase was above the "significance" level. The emissions increase for all pollutants (NOx, SO_2, CO, PM, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4 and Fluorides) except Pb was above the respective PSD significant level threshold.

The Plant Washington will be located in Washington County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$ and PM_{10}, NO_X, CO, and ozone (VOC).

The EPD review of the data submitted by Plant Washington related to the proposed plant indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of NOx, SO_2, CO, PM, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4 and Fluorides, as required by federal PSD regulation 40 CFR 52.21(j) and 40 CFR 51.165 (for $PM_{2.5}$).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 300 km of the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Plant Washington for the construction and operation of a supercritical pulverized coal-fired power plant rated at 850 MW net output capacity. Various conditions have been incorporated into the draft permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit is included in Appendix B.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On January 17, 2008, Plant Washington submitted an application for an air quality permit to construct and operate a supercritical pulverized coal fired power plant rated at 850 MW net output capacity. The facility is located at Mayview Road in Sandersville, Washington County.

Application that was submitted on December 3, 2008 replaces the application that was submitted on January 17, 2008. This preliminary determination is based on the application that was submitted on December 3, 2008 and the subsequent submittals.

Based on the proposed project description and data provided in the permit application, the estimated emissions of regulated pollutants from the facility are listed in Table 1-1 below:

Table 1-1: Emissions from the Project

Pollutant	Potential Controlled Emissions (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	696	25	Yes
PM_{10}	678	15	Yes
$PM_{2.5}$	454	10	Yes
VOC	110	40	Yes
NO_X	1836	40	Yes
CO	3642	100	Yes
SO_2	1896	40	Yes
TRS	0	10	No
Pb	0.58	0.6	No
Fluorides	8.0	3	Yes
H_2S	0	10	No
SAM (H_2SO_4)	145	7	Yes

The emissions calculations for Tables 1-1 can be found in detail in the facility's PSD application (see exhibit A of Application No. 17924). These calculations have been reviewed and approved by the Division.

Based on the information presented in Table 1-1 above, Plant Washington, as specified per Georgia Air Quality Application No. 17924, is classified as a new major source under PSD because the potential emissions of NOx, SO_2, CO, PM, PM_{10}, $PM_{2.5}$ and VOC exceeds 100 tpy and it belongs to one of the 28 specific source categories (fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input).

Through its new source review procedure, EPD has evaluated Plant Washington's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

According to Application No. 17924, Plant Washington has proposed to construct and operate a supercritical pulverized coal-fired power plant rated at 850 MW net output capacity.

The proposed project consists of one supercritical pulverized coal fired steam generating unit and associated steam turbine generators along with other auxiliary equipments. The generating plant will be rated at 850 MW net output capacity, and will be designed to burn sub-bituminous coal (Powder River Basin, or PRB coal) or up to a 50/50 blend (by weight) of eastern bituminous coal (Illinois #6) and PRB. Although the unit will be designed for use with PRB and Illinois #6 coals, it will also have the capability of utilizing bituminous and sub-bituminous coals with equivalent characteristics of PRB and Illinois #6. The unit will be used for “base load” electricity generating operations. The unit may also operate for extended periods at loads within the operating range of 40 to 100 percent load during the shoulder months (spring and fall).

Pulverized coal will be combusted in the facility main boiler. Produced steam will be used to drive a steam turbine, which in turn will create electricity through the mechanical energy created by driving the steam turbine generator shaft. The proposed project will include the following:

- One supercritical pulverized coal fired boiler – The boiler will be a pulverized coal single reheat, with low NOx burners and overfire air. The maximum heat input rate of the boiler will be 8,300 MMBtu/hr while firing coal. Ultra low sulfur fuel oil will be used for unit start-up and for flame stabilization. The maximum heat input rate of the boiler while burning fuel oil will be 1,300 MMBtu/hr. The air pollution control equipment in use on the boiler will include a selective catalytic reduction (SCR) system for control of NOx emissions, sorbent injection systems for the control of H_2SO_4 and mercury emissions, fabric filter for the control of PM emissions and a wet limestone scrubber for control of SO_2 emissions.

- Cooling Tower – The cooling tower will be comprised of thirty-four cells using drift eliminators for the reduction of drift.

- Material handling and storage facilities

    - Facilities for receiving, handling, storing, blending and processing two types of coal, Sub-bituminous and Bituminous. The preliminary design coal basis for Plant Washington will be based on use of PRB and Illinois #6 coals, with a nominal consumption rate of approximately 417 tons per hour (ton/hr) of blended coal at a 50/50 blend or at a rate of approximately 488 ton/hr when burning only PRB coal. The facility will be designed to handle any similar sub-bituminous and bituminous coals.

      Coal will be delivered using railcars. At the railcar unloading station, coal will be dumped into four underground receiving hoppers, which discharged onto underground dual unloading belt feeders. The unloading station will be enclosed and will utilize a dust suppression system with the capability to apply a chemical mixture dust suppressant. During periods of precipitation and/or high humidity, a water spray application may be used instead of the chemical mixture.

      The unloading belt feeders will transfer coal onto the unloading conveyor that moves coal to the transfer point above the lowering well. From this point, PRB coal will be dumped into the PRB lowering well. At the lowering wells, the coal will be stacked out to the respective active coal storage piles. Fugitive dust emissions from the end of the unloading conveyor are controlled by a dust collection system called an ‘insertable dust collector’. To accommodate interruptions of fuel supply, the coal handling system includes inactive coal storage piles for both PRB and Illinois #6 coals next to the respective active piles. Coal is transferred from the active piles to inactive storage using mobile equipment such as bulldozers and scrapers. When needed, coal will be transferred from the inactive piles to the active piles using mobile equipment. Ninety days of storage will be maintained on site.

Coal will be pulled from active piles via eight grizzly hoppers and feeders to two reclaim conveyors. These emission points will be located underground. Two hoppers from PRB active storage and two hoppers from Illinois #6 active storage feed reclaim conveyor 1. Two hoppers from PRB active storage and two hoppers from Illinois #6 active storage feed reclaim conveyor 2. Belt scales weighing Illinois #6 and the total coal flow on the reclaim conveyors will facilitate blending the coals to specific ratios.

Reclaim conveyors will convey the coal to surge bin, which is located inside the crusher house. From the surge bin, the coal will be fed to crusher via two diverters with fixed grizzlies. Emissions from crusher house will be controlled by a baghouse. The crushed coal will be transferred to boiler silo conveyors via two feed conveyors 1 and 2. Silo conveyors 1 and 2 will be outfitted with traveling trippers, which will fill 6 boiler silos. Boiler silos will feed pulverizers. All the emissions will be controlled by a baghouse.

- Facilities for receiving, handling, storing and process limestone, which is a raw material for Wet Limestone Scrubber
  Limestone will be delivered using railcars. At the unloading station, limestone will be dumped into four underground receiving hoppers, which will discharge onto underground dual unloading belt feeders. The unloading station will be enclosed and will utilize a dust suppression system with the capability to apply a chemical mixture dust suppressant.

  The unloading belt feeders will transfer limestone onto the unloading conveyor, which conveys limestone to the limestone stacking tube where it is stacked out to the limestone storage pile. The unloading conveyor will include a dust collection system called an 'insertable dust collector'. Limestone will be pulled from active pile via two grizzly hoppers with feeders to reclaim conveyor. Reclaim conveyor will convey the limestone to silo located at the limestone reagent preparation area. Limestone preparation area is controlled by baghouse.

- Facilities for handling and storing of fly ash and bottom ash

  - Facilities for handling and storing of fly ash
    The fly ash system will pneumatically convey (capacity of 50 tph) dry free flowing ash from the baghouse hoppers and air heater hoppers to the fly ash storage silos, which will have a storage capacity of 3600 tons. The fly ash handling system will be designed to include a vacuum system to transfer ash from the baghouse and air heater hoppers through a filter separator that deposits the ash into silo. The fly ash silo will be equipped with a bin vent filter. The ash will be conditioned with water and will be loaded into trucks for transportation to an on-site storage.

  - Facilities for handling and storage of bottom ash
    The bottom ash handling system consists of submerged chain conveyor, which will collect the boiler bottom ash and pyrites from the coal pulverizers. This chain conveyor will discharge ash onto transfer conveyor which discharges into a three-sided ground level bunker. From the bunker the ash will be loaded onto trucks for transportation to an on-site storage.

  - Facilities for handling and storing of gypsum
    Operation of wet scrubber will produce gypsum as a by-product. Vacuum belt will dewater the gypsum and it will be transferred to load-out conveyor. This conveyor will transfer gypsum to the 800 ton capacity storage bin, which will hold 10 days of production. Trucks will transport the gypsum to the on-site long-term storage. Gypsum will be transferred from the storage bin to a radial stacker that will pile the gypsum on the ground near the bin when trucks are not operating.

  - Facilities for receiving, handling, storing and delivering mercury removal sorbent
    System to handle the sorbent will include self-unloading of trucks and pneumatic conveying of the sorbent to the storage silo. The silo will be equipped with bin vent filter to support sorbent unloading operations.

  - Facilities for receiving, handling, storing and delivering sulfur trioxide (SO_3) removal sorbent for the control of sulfuric acid mist emissions
    System to handle the sorbent will include self-unloading of trucks and pneumatic conveying of the sorbent to the storage silo. The silo will be equipped with bin vent filter to support sorbent unloading operations.

  - Facilities for receiving, handling and storing Lime and Soda Ash
    As part of the raw water treatment system at the facility, soda ash and lime will be used to reduce iron and phosphorous levels prior to use in industrial services at the facility. System to handle these materials will include self-unloading of trucks and pneumatic conveying of the material to their respective storage silos. These silos will be equipped with bin vent filter.

  - Facilities for receiving, handling and storing anhydrous ammonia, which is a raw material for SCR system.
    The ammonia will be stored in pressurized storage tanks each with an emergency relief valve. A risk management plan will be prepared to address on-site storage and handling of anhydrous ammonia pursuant to the requirements of 40 CFR 68 Subpart G.

- An emergency 1,500 HP (engine output) diesel fired generator and associated fuel storage tank of 750 gallons (gal) capacity.

- An emergency 350 HP diesel fired fire water pump and associated fuel storage tank of 250 gal capacity.

- One 240 MMBtu/hr, ultra low sulfur No. 2 fuel oil fired auxiliary boiler and associated fuel oil tank of 350,000 gal capacity. The boiler will be equipped with low NOx burner and flue gas recirculation (FGR). Operation of the boiler will be limited to a ten percent annual capacity factor.

- Solid Materials handling Facility for long term storage of process byproducts
  The facility will maintain a long-term storage facility for fly ash, bottom ash and gypsum. The materials will be loaded into trucks from the appropriate storage silo or storage bunker in the main operational areas of the facility and transported to the on-site storage. The fly ash can be sold to concrete production facilities and the gypsum can be used to produce wall board.

The Plant Washington permit application and supporting documentation are included in Appendix C of this Preliminary Determination and can be found online at www.georgiaair.org/airpermit.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. *Georgia Rule 391-3-1-.03(8)(b)* continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1-.02(2)(b) - Standard for Visible Emissions

This regulation limits opacity to less than forty (40) percent, except as may be provided in other more restrictive or specific rules of *Georgia Rule 391-3-1-.02(2).* This standard applies to direct sources of emissions such as stationary structures, equipment, machinery, stacks, flues, pipes, exhausts, vents, tubes, chimneys or similar structures. This regulation is applicable to coal conveyor stackouts, coal crusher house, tripper decker, fly ash mechanical exhausters, fly ash silo, limestone stackout, limestone preparation building, SO_3 and mercury sorbent silos, soda ash and lime silos, cooling towers, emergency generator, firewater pump and other supporting equipment with the capability of emitting particulates.

Georgia Rule 391-3-1-.02(2)(d) - Standards for Fuel Burning Equipment

This regulation limits particulate matter emissions from fuel burning equipment.

The coal fired boiler S1 is subject to rule *391-3-1-.02(2)(d)(2)(iii)* as the boiler will be constructed after January 1, 1972 and the capacity is greater than 250 MMBtu/hr. This rule limits the allowable weight of emissions of fly ash and/or particulate matter from boiler to 0.1 lb/MMBtu heat input.

The auxiliary boiler S45 is subject to rule *391-3-1-.02(2)(d)(2)(ii)* as the boiler will be constructed after January 1, 1972 and the capacity is greater than 10 MMBtu/hr and less than 250 MMBtu/hr. This rule limits the allowable weight of emissions of fly ash and/or particulate matter from boiler to 0.102 lb/MMBtu heat input.

The coal fired boiler S1 and auxiliary boiler S45 are subject to rule *391-3-1-.02(2)(d)(3)* as they will be constructed after January 1, 1972. This rule limits the opacity to less than twenty (20) percent except for one six-minute period per hour of not more than twenty-seven (27) percent opacity.

The coal fired boiler S1 is subject to rule *391-3-1-.02(2)(d)(4)* as the boiler will be constructed after January 1, 1972 and the capacity is greater than 250 MMBtu/hr. This rule limits the emissions of NOx to 0.7 lb/MMBtu while firing coal and 0.3 lb/MMBtu while firing oil. When coal and oil burned simultaneously in any combination, the applicable standard for NOx in lb/MMBtu shall be determined by proration. Compliance shall be determined by using the following formula:

$$x (0.3) + y (0.7) / (x + y)$$

where, x = percent of total heat input derived from oil
y = percent of total heat input derived from coal

Georgia Rule 391-3-1-.02(2)(e) - Emission Limitations and Standards for Particulate Emission from Manufacturing Processes

$E = 4.1 P^{0.67}$; for process input weight rate up to and including 30 tons per hour.
$E = 55 P^{0.11} - 40$; for process input weight rate above 30 tons per hour.

This regulation is applicable to coal conveyor stackouts, coal crusher house, tripper decker, fly ash mechanical exhausters, fly ash silo, limestone stackout, limestone preparation building, SO_3 and mercury sorbent silos, soda ash and lime silos, cooling towers and other supporting equipment with the capability of emitting particulates.

Georgia Rule 391-3-1-.02(2)(g) - Standard for Sulfur Dioxide

The coal fired boiler S1 is subject to *391-3-1-.02(2)(g)(1)* as the boiler will be constructed after January 1, 1972 and the capacity is greater than 250 MMBtu/hr. As per the rule, the boiler may not emit sulfur dioxide equal to or exceeding:

- 0.8 pounds of sulfur dioxide per million BTUs of heat input derived from liquid fossil fuel or derived from liquid fossil fuel and wood residue;

- 1.2 pounds of sulfur dioxide per million BTUs of heat input derived from solid fossil fuel or derived from solid fossil fuel and wood residue;

- When different fossil fuels are burned simultaneously in any combination, the applicable standard expressed as pounds of sulfur dioxide per million BTUs of heat input shall be determined by proration using the following formula:

  $a = [y(0.80) + z(1.2)]/(y + z)$

  where:
  y = percent of total heat input derived from liquid fossil fuel
  z = percent of total heat input derived from solid fossil fuel
  a = the allowable emission in pounds per million BTUs

The coal fired boiler S1 is subject to *391-3-1-.02(2)(g)(3)* which states notwithstanding the limitations on sulfur content of fuels stated in paragraph 2. in *Georgia Rule 391-3-1-.02(2)(g)*, sulfur content can be allowed to be greater than that allowed in paragraph 2. in *Georgia Rule 391-3-1-.02(2)(g)*, provided that the source utilizes sulfur dioxide removal and the sulfur dioxide emission does not exceed that allowed by paragraph 2. in *Georgia Rule 391-3-1-.02(2)(g)*, utilizing no sulfur dioxide removal.

The auxiliary boiler S45 is subject to *391-3-1-.02(2)(g)(2)* as the boiler capacity is greater than 100 MMBtu/hr. This rule limits the fuel sulfur content to 3.0 percent by weight.

The emergency generator EG1 and fire water pump EP1 are subject to *391-3-1-.02(2)(g)(2)* as the capacity of each unit is less than 100 MMBtu/hr. This rule limits the fuel sulfur content to 2.5 percent by weight.

<u>Georgia Rule 391-3-1-.02(2)(n) - Standard for Fugitive Dust</u>

This rule requires Plant Washington to take all reasonable precautions to prevent such dust from becoming airborne for any operation, process, handling, transportation or storage facility which may result in fugitive dust. This rule limits opacity from such sources to less than 20 percent.

This limit applies to fugitive emission sources at Plant Washington including coal rail unloading, active and inactive coal piles and transfer points, ash transfer points and ash handling, gypsum handling, limestone unloading, limestone pile and transfer point, and paved and unpaved road travel.

Compliance with the above state rules is expected. As discussed in Section 4.0, the PSD BACT limits are all at least as stringent as, and in most cases are significantly more stringent than the state rules.

<u>Georgia Rule 391-3-1-.02(2)(ttt) - Standard for Mercury Emissions from New Electric Generating Units</u>

The coal fired boiler S1 is subject to *391-3-1-.02(2)(ttt)* as the boiler will be installed after January 1, 2007 and generates greater than 25 MW of electricity for sale. This rule requires the boiler to meet the appropriate Division Director approved requirements of best available control technology in controlling emissions of mercury. A BACT evaluation has been conducted for the coal fired boiler for control of mercury emissions. Please refer to Section 4.0 of this document for BACT evaluation for mercury.

Federal Rule - PSD

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

Georgia has adopted a regulatory program for PSD permits, which the Unites States Environmental Protection Agency (EPA) has approved as part of Georgia's State Implementation Plan (SIP). This regulatory program is located in the Georgia Rules at 391-3-1-.02(7). This means that Georgia EPD issues PSD permits for new major sources pursuant to the requirements of Georgia's regulations. It also means that Georgia EPD considers, but is not legally bound to accept, EPA comments or guidance. A commonly used source of EPA guidance on PSD permitting is EPA's Draft October 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting (NSR Workshop Manual). The NSR Workshop Manual is a comprehensive guidance document on the entire PSD permitting process.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation

Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

EPA's NSR Workshop Manual includes guidance on the 5-step top-down process for determining BACT. In general, Georgia EPD requires PSD permit applicants to use the top-down process in the BACT analysis, which EPD reviews. The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

Step 1: Identification of all control technologies;
Step 2: Elimination of technically infeasible options;
Step 3: Ranking of remaining control technologies by control effectiveness;
Step 4: Evaluation of the most effective controls and documentation of results; and
Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

New Source Performance Standards (NSPS)

40 CFR 60 Subpart A *- General Provisions*

Except as provided in Subparts B and C of 40 CFR Part 60, the provisions of this regulation apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility [40 CFR 60.1(a)]. Plant Washington is a new facility with several pieces of equipment and/or processes subject to NSPS. Any new or revised standard of performance promulgated pursuant to Section 111(b) of the Clean Air Act apply to Plant Washington's applicable equipment and/or processes and any applicable source/equipment for which the construction or modification is commenced after the date of publication in 40 CFR Part 60 of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that equipment and/or processes [40 CFR 60.1(b)].

40 CFR 60 Subpart Da **-** *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*

Applicability

This regulation is applicable to the coal fired boiler S1, since the regulation applies to each electric utility steam generating unit that is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour) heat input of fossil fuel (either alone or in combination with any other fuel) and was constructed, modified, or reconstructed after September 18, 1978 [40 CFR 60.40Da (a)].

Emission standards

Particulate matter

The coal fired boiler will be constructed post February 28, 2005 and hence the following particulate matter standard applies:

On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the coal fired boiler shall not emit particulate matter into the atmosphere in excess of either:
[40 CFR 60.42Da(c)]

1. 18 nanograms per joule (ng/J) (0.14 lb/MWh) gross energy output; or
2. 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

As an alternative to meeting either of the above requirements, Plant Washington may elect to meet the following requirements:

On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the coal fired boiler shall not emit particulate matter into the atmosphere in excess of either:
[40 CFR 60.42Da(d)]

1. 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

2. 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for the coal fired boiler when combusting solid, liquid, or gaseous fuel

NSPS Subpart Da PM emission limit is subsumed by the PM emission limit under PSD BACT requirement. Compliance with the PM emission limit is determined through PM Continuous Emissions Monitoring System (CEMS).

Opacity

On and after the date the initial particulate performance test is completed or required to be completed under §60.8, whichever date comes first, the coal fired boiler shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity [40 CFR 60.42Da(b)].

Continuous Opacity Monitoring System (COMS) is required to determine compliance with the opacity standard. However, units that use PM CEMS to meet compliance with PM standard are exempt from COMS requirement. Compliance with the opacity standard is determined through PM CEMS [40 CFR 60.48Da(o) and 40 CFR 60.49Da(u)].

SO_2

The coal fired boiler will be constructed post February 28, 2005 and hence the following SO_2 standard applies:

On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the coal fired boiler shall not cause to be discharged into the atmosphere, any gases that contain SO_2 in excess of either:
[40 CFR 60.43Da(i)(1)]

1. 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or
2. 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis

NSPS Subpart Da SO_2 emission limit is subsumed by the SO_2 emission limit under PSD BACT requirement. Compliance with the SO_2 emission limit is determined through SO_2 CEMS.

NOx

The coal fired boiler will be constructed post February 28, 2005 and hence the following NOx standard applies:

On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the coal fired boiler shall not cause to be discharged into the atmosphere, any gases that contain NOx (expressed as NO_2) in excess of the following:
[40 CFR 60.44Da(e)(1)]

130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis except as provided under 60.48Da(k) that applies to duct burners.

NSPS Subpart Da NOx emission limit is subsumed by the NOx emission limit under PSD BACT requirement. Compliance with the NOx emission limit is determined through NOx CEMS.

Mercury

On February 8, 2008, the District of Columbia (D.C.) Circuit Court of Appeals vacated USEPA's final Clean Air Mercury Rule (CAMR), which effectively vacated NSPS Subpart Da for mercury. Hence Mercury emission limits under NSPS Subpart Da are not applicable to the coal fired boiler.

40 CFR 60 Subpart Db *- Standard of Performance for Industrial-Commercial-Institutional Steam Generating Units*

Applicability

This regulation applies to auxiliary boiler S45, as the regulation applies to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr))[40 CFR 60.40b(a)].

Emission Standards

SO_2

The auxiliary boiler will not be subject to SO_2 limit under 40 CFR 60.42b(k)(1) as it will be constructed post February 28, 2005 and combusts only low sulfur oil (less than 0.3 weight percent sulfur) with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less [40 CFR 60.42b(k)(2)].

Particulate Matter

The auxiliary boiler will not be subject to particulate matter limit under 40 CFR 60.43b(h)(1) as it will be constructed post February 28, 2005 and combusts only oil that contains no more than 0.3 weight percent sulfur and do not use post-combustion technology to reduce SO_2 or PM emissions [40 CFR 60.43b(h)(5)].

Opacity

On and after the date the initial particulate performance test is completed or required to be completed under §60.8, whichever date comes first, the auxiliary boiler shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity [40 CFR 60.43b(f)].

Opacity standard applies at all times except during periods of startup, shutdown and malfunction [40 CFR 60.43b(g)].

NOx

The auxiliary boiler will be constructed post July 9, 1997 and the facility has taken a federally enforceable limit for the annual capacity factor of 10 percent or less for oil; hence the NOx emission limit does not apply [40 CFR 60.44b(l)(1)].

40 CFR 60 Subpart Kb *- Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*

This regulation applies to each storage vessel with a capacity greater than or equal to 75 m^3 (19,813 gallons) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984[40 CFR 60.110b(a)] except as follows:

This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 (39,890 gallons) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 (19,813 gallons) but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa [40 CFR 60.110b(b)].

The 350,000-gallon distillate fuel oil tank TNK1 is not subject to this subpart as the vapor pressure of distillate fuel oil is less than 3.5 kPa. Tanks TNK2 and TNK3 are also not subject to this subpart, as the size of each tank is less than 19,813 gallons.

40 CFR 60 Subpart Y *- Standards of Performance for Coal Preparation Plants*

This regulation is applicable to any of the following affected facilities in coal preparation plants which process more than 181 Mg (200 tons) per day and that commences construction after October 24, 1974: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems [40 CFR 60.250(a)].

Plant Washington will not have a thermal dryer or coal cleaning equipment, but will have coal conveying operations (conveyors), crushing operations and coal storage systems (open storage piles are exempt) (Emission Units A4, S40, S41, S46 and S47) which are subject to this regulation. These operations will be subject to the opacity limit and compliance will be demonstrated through the use of EPA Method 9 and the procedures established in §60.11. The opacity limit applicable to facility operations under Subpart Y is given below:

On and after the date on which the performance test required to be conducted by §60.8 is completed, Plant Washington shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater [40 CFR 60.252(c)].

40 CFR 60 Subpart OOO *- Standards of Performance for Nonmetallic Mineral Processing Plants*

This regulation is applicable to the following affected facilities in fixed or portable nonmetallic mineral processing plants that commences construction after August 31, 1983: each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station. Also, crushers and grinding mills at hot mix asphalt facilities that reduce the size of nonmetallic minerals embedded in recycled asphalt pavement and subsequent affected facilities up to, but not including, the first storage silo or bin [40 CFR 60.670(a)].

This regulation applies to the Limestone Management Particulate Sources (Emission Units A5, S42 and S48) and associated conveying system at Plant Washington.

Affected facilities with capture systems used to capture and transport PM to a control device must meet a PM emissions limit of 0.032 g/dscm (0.014 gr/dscf) [40 CFR 60.672(a)]. Limestone stackout (Emission Unit S48) is subject to this regulation. Method 5 or Method 17 shall be used to determine compliance.

Fugitive emissions from affected facilities without capture systems and fugitive emissions escaping capture systems must meet an opacity limit of 7 percent [40 CFR 60.672(b)]. Limestone railcar unloading station (Emission Unit A5) is subject to this regulation. Method 9 shall be used to determine compliance. Periodic inspection of water sprays is also required.

If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in paragraphs (a) and (b) of section 40 CFR 60.672, **or** the building enclosing the affected facility or facilities must comply with the following emission limits:
[40 CFR 60.672(e)]

(1) Fugitive emissions from the building openings (except for vents as defined in 60.671) must not exceed 7 percent opacity; and
(2) Vents in the building must meet a PM emissions limit of 0.032 g/dscm (0.014 gr/dscf).

Limestone preparation building (Emission Unit S45) is subject to this regulation. Method 5 (or Method 17 and Method 9) shall be used to determine compliance.

40 CFR 60 Subpart IIII *- Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

This regulation is applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of § 60.4200.

1500 HP Diesel Fired Emergency Generator EG1 will commence construction after July 11, 2005 and will be manufactured after April 1, 2006; hence it will be subject to the requirements of NSPS Subpart IIII. The generator shall only use diesel fuel that has a maximum sulfur content of 15 parts per million (ppm) (0.0015% by weight) [40 CFR 80.510(b)]. The accumulated non-emergency service (maintenance check and readiness testing) time for the Emergency Diesel Generator EG1 shall not exceed 100 hours per year [40 CFR 60.4211(e)].

350 HP Diesel Fired Emergency Fire Water Pump EP1 will commence construction after July 11, 2005 and will be manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006; hence it will be subject to the requirements of NSPS Subpart IIII. The fire water pump shall only use diesel fuel that has a maximum sulfur content of 15 parts per million (ppm) (0.0015% by weight) [40 CFR 80.510(b)]. The accumulated non-emergency service (maintenance check and readiness testing) time for the Emergency Fire Water Pump EP1 shall not exceed 100 hours per year for each unit [40 CFR 60.4211(e)].

National Emissions Standards For Hazardous Air Pollutants

40 CFR 63 Subpart A *- General provisions*

This regulation contains national emission standards for hazardous air pollutants (NESHAP) established pursuant to section 112 of the Act as amended November 15, 1990. These standards regulate specific categories of stationary sources that emit (or have the potential to emit) one or more hazardous air pollutants listed in this part pursuant to section 112(b) of the Act. The standards in this part are independent of NESHAP contained in 40 CFR Part 61. The NESHAP in part 61 promulgated by signature of the Administrator before November 15, 1990 (i.e., the date of enactment of the Clean Air Act Amendments of 1990) remain in effect until they are amended, if appropriate, and added to 40 CFR Part 63 [40 CFR 63.1(a)(1) and (2)]. No emission standard or other requirement established under 40 CFR Part 63 shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 111, part C or D or any other authority of this Act), or a standard issued under State authority. The Administrator may specify in a specific standard under this part that facilities subject to other provisions under the Act need only comply with the provisions of that standard [40 CFR 63.1(a)(3)]. Plant Washington is a new facility with some of the units applicable to this regulation.

40 CFR 63 Subpart B *- Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)*

The requirements of §63.40 through 63.44 of 40 CFR Part 63, Subpart B carry out section 112(g)(2)(B) of the 1990 Amendments [40 CFR 63.40(a)]. The requirements of §63.40 through 63.44 of 40 CFR Part 63, Subpart B apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants after the effective date of section 112(g)(2)(B) (as defined in §63.41) and the effective date of a title V permit program in the State or local jurisdiction in which the major source is (or would be) located unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h), or section 112(j) and incorporated in another subpart of part 63, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction project before the effective date of section 112(g)(2)(B) [40 CFR 63.40(b)].

40 CFR 63 Subpart B is referred to as "Case-by-Case MACT," or as a 112(g) determination. Section 112 of the Clean Air Act as amended in 1990 requires that EPA issue emission standards for all major sources of 188 listed HAPs. Section 112(g) is intended to ensure that HAP emissions do not increase excessively if a facility is constructed or reconstructed before EPA issues a MACT standard for that particular category of sources or facilities. When 112(g) is triggered by a construction or modification project, EPD is required to make case-by-case MACT determination. Section 112(g) became effective in Georgia on June 30, 1998.

40 CFR 63 Subpart ZZZZ *- National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

This regulation is applicable to Stationary Reciprocating Internal Combustion Engines (RICE) at a major or area source of HAP emissions as specified in paragraphs (a) through (e) of § 63.6585 and (a) through (c) of § 63.6590.

1500 HP Diesel Fired Emergency Generator EG1 is a new emergency stationary RICE (compression ignition) with a rating of more than 500 HP and located at a major source of HAP emissions. It does not have to meet the requirements of Subpart ZZZZ and Subpart A except for the initial notification requirements of § 63.6645(h) [40 CFR 63.6590(b)(1)(i)]. It is not required to add this initial notification requirement in the permit as it is already satisfied via the permit application.

350 HP Diesel Fired Emergency Firewater Pump EP1 is a new emergency stationary RICE (compression ignition) with a rating of less than 500 HP and located at a major source of HAP emissions. It must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII. [40 CFR 63.6590(c)]

<u>40 CFR 63 Subpart DDDDD</u> *- National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*

The proposed auxiliary boiler S45 would have been subject to 40 CFR 63 Subpart DDDDD. However this regulation was vacated by the District of Columbia (D.C.) Circuit Court of Appeals in June 2007. Hence the auxiliary boiler S45 is subject to 112(g) case-by-case MACT determination. The facility has submitted a case-by-case MACT determination for the auxiliary boiler S45 and it is addressed in Appendix A of this document.

Federal Rule – Clean Air Mercury Rule (CAMR)

40 CFR 60 Subpart Da [40 CFR 60.45da] *and* ***40 CFR 60 Subpart HHHH –*** *Emission Guidelines and Compliance Times for Coal-Fired Electric Generating Units.*

40 CFR 60.45da establishes the emissions standards for mercury (Hg) for coal-fired electric utility steam generating units. 40 CFR 60 Subpart HHHH establishes the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State mercury (Hg) Budget Trading Program, under section 111 of the Clean Air Act (CAA) and §60.24(h)(6), as a means of reducing national Hg emissions.

On March 15, 2005, EPA issued CAMR to permanently cap and reduce mercury emissions from coal-fired power plants. The CAMR establishes "standards of performance" limiting mercury emissions from new and existing coal-fired power plants and creates a market-based cap-and-trade program to reduce nationwide utility emissions of mercury in two distinct phases.

On February 8, 2008, the District of Columbia (D.C.) Circuit Court of Appeals vacated USEPA's final Clean Air Mercury Rule (CAMR). At the same time, the court vacated USEPA's rule removing power plants from the Clean Air Act list of sources of hazardous air pollutants.

As power plants may now be reinstated to the list of Section 112(c) source categories, such units are now required to submit a Section 112(g) case-by-case MACT analysis for applicable HAPs. A case-by-case MACT analysis is required for the coal fired boiler S1. The facility has submitted a case-by-case MACT determination for the coal fired boiler S1 and it is addressed in Appendix A of this document.

Federal Rule – Clean Air Interstate Rule (CAIR)

40 CFR 96 Subpart AA *- CAIR NOx Annual Trading Program General Provisions,* ***Subpart BB*** *– CAIR Designated Representative for CAIR NOx Sources,* ***Subpart CC*** *– Permits,* ***Subpart EE*** *– CAIR NOx Allowance Allocations,* ***Subpart FF*** *– CAIR NOx Allowance Tracking System,* ***Subpart GG*** *– CAIR NOx Allowance Transfers,* ***Subpart HH*** *– Monitoring and Reporting*

These regulations established the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State Clean Air Interstate Rule (CAIR) NO_X Annual Trading Program, under section 110 of the Clean Air Act and §51.123 of Chapter I, as a means of mitigating interstate transport of fine particulates and nitrogen oxides. The owner or operator of a unit or a source was to comply with the requirements of these regulations as a matter of federal law only if the State with jurisdiction over the unit and the source incorporated by reference such subparts or otherwise adopted the requirements of such subparts in accordance with §51.123(o)(1) or (2) of Chapter I, the State submitted to the Administrator one or more revisions of the State implementation plan that included such adoption, and the Administrator approved such revisions.

40 CFR 96 Subpart AAA *- Clean Air Interstate Rule [CAIR] SO_2 Trading Program General Provisions,* ***Subpart BBB*** *– CAIR Designated Representative for CAIR SO_2 Sources,* ***Subpart CCC*** *– Permits,* ***Subpart FFF*** *– CAIR SO_2 Allowance Tracking System,* ***Subpart GGG*** *– CAIR SO_2 Allowance Transfers,* ***Subpart HHH*** *– Monitoring and Reporting*

These regulations established the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State Clean Air Interstate Rule (CAIR) SO_2 Trading Program, under section 110 of the Clean Air Act and §51.124 of Chapter I, as a means of mitigating interstate transport of fine particulates and sulfur dioxide. The owner or operator of a unit or a source was to comply with the requirements of these regulations as a matter of federal law only if the State with jurisdiction over the unit and the source incorporated by reference such subparts or otherwise adopts the requirements of such subparts in accordance with §51.124(o)(1) or (2) of Chapter I, the State submitted to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approved such revisions.

On May 12, 2005, EPA issued CAIR to make reductions in emissions of NOx and SO_2 in the eastern United States. On July 11, 2008, the District of Columbia (D.C.) Circuit Court of Appeals vacated CAIR in its entirety. On November 17, 2008 the United States EPA filed a reply in support of its petition for rehearing in the Clean Air Interstate Rule case. On December 28, 2008, the District of Columbia (D.C.) Circuit Court of Appeals has remanded the CAIR rule without vacatur. Therefore, this rule will remain in place until EPA issues a new rule to replace CAIR in accordance with the July 11, 2008 decision.

Coal fired boiler S1 is subject to this regulation as it burns fossil fuel and has capacity greater than 25 MW producing electricity for sale. The applicability of this regulation is not addressed in this permit as it becomes applicable only when Plant Washington becomes an operational facility.

Federal Rule – Acid Rain Program

40 CFR 72 *- Permits Regulation,* ***40 CFR 73*** *- SO_2 Allowance System,* ***40 CFR 74*** *- SO_2 OPT-INS,* ***40 CFR 75*** *- Continuous Emissions Monitoring,* ***40 CFR 76*** *- Acid Rain NOx Emissions Reduction Program,* ***40 CFR 77*** *- Excess Emissions,* ***40 CFR 78*** *- Appeal Procedures*

Acid rain program is implemented to make reductions in emissions of NOx and SO_2. Coal fired boiler S1 is subject to the acid rain regulations as it burns fossil fuel and has capacity greater than 25 MW producing electricity for sale. Acid rain permit application for new unit is due 24 months before the unit commences operation. Plant Washington has not submitted the Acid Rain Permit Application forms as part of Application No. 17924 and needs to apply for an Acid Rain program permit at least 24 months before operation of the coal fired boiler S1 begins.

Federal Rule – Title V Operating Permit

40 CFR Part 70 *- State Operating Permit Programs*

The regulations in 40 CFR Part 70 provide for the establishment of comprehensive State air quality permitting systems consistent with the requirements of title V of the Clean Air Act (Act) (42 U.S.C. 7401, *et seq.*). These regulations define the minimum elements required by the Clean Air Act for State operating permit programs and the corresponding standards and procedures by which the Administrator will approve, oversee, and withdraw approval of State operating permit programs. Georgia has established such a program. Plant Washington, because it can potentially emit applicable pollutants above the applicable major source thresholds, is subject to 40 CFR Part 70. All sources subject to these regulations must have a permit to operate that assures compliance by the source with all applicable requirements [40 CFR 70.1(b)].

Plant Washington must prepare and submit an initial Title V Operating Permit Application for the operation of the facility in accordance with 40 CFR 70.5. Plant Washington must file a complete application to obtain the part 70 permit within 12 months after commencing operation on or before such earlier date as the Division may establish [40 CFR 70.5(a)(ii)]. The Division requires that Plant Washington submit a complete initial Title V Operating Permit Application within 12 months of commencing operation.

Federal Rule – Compliance Assurance Monitoring (CAM)

40 CFR 64 *- Compliance Assurance Monitoring*

Under CAM Regulations, facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program [40 CFR 64.2(a)].

Plant Washington is required to address CAM applicability in their initial Title V Operating Permit application, which will be due within 12 months after the facility commences operation.

Federal Rule – 40 CFR 68 – Chemical Accident Prevention Provisions

40 CFR 68 *- Chemical Accident Prevention Provisions*

This rule applies to any stationary source and to the owner or operator of any stationary source subject to any requirement under 40 CFR Parts 68, as amended. This rule requires the facility to prepare a risk management plan to address on-site storage and handling of anhydrous ammonia pursuant to the requirements of 40 CFR 68 Subpart G.

State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7 (NSPS emission standards are not covered by these provisions. Instead, startup and shutdown emissions are addressed within the NSPS standards themselves). Excess emissions from the coal fired boiler S1 are most likely to occur during periods of startup and/or shutdown because during these periods of operation, operating conditions such as temperature and flow rates of the unit exhaust from the boiler may not be conducive to proper operation of the applicable control systems (SCR and Wet Scrubber), resulting in emissions of applicable pollutants above usual levels.

In NSPS 40 CFR 60.8(c), it states "Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test, nor shall emission in excess of the level of the applicable emission limits during periods of startup, shutdown and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard." For new steam electric generating facilities, compliance with the NOx and SO_2 standards in 40 CFR 60 Subpart Da is based on a 30-day rolling average, excluding startups and shutdowns. Excess emissions of the short term (ppm or lb/MMBtu) PSD BACT limits during startup and shutdown are subject to the provisions in Georgia Rule 391-3-1-.02(2)(a)7.

Although the facility is expected to be a base load power generation facility, there will be occasions when the facility will be out of service for planned and unplanned maintenance and reserve shutdown. In such cases, the facility will need to undergo a startup process to return to service. The unit cold startup procedure for the coal fired boiler S1 will include a 15-hour startup cycle, beginning with boiler using ultra low sulfur No. 2 distillate fuel oil. The combustion of oil is used to slowly warm the boiler systems to reduce thermal stresses on the boiler system during startup and to provide an ignition source for the coal burners. At the same time, the auxiliary boiler produces steam to seal and warm up the steam turbine to assist in the startup process to full load. During the entire start up process, the fabric filter baghouse is used for control of PM emissions. The wet limestone scrubber system used for control of SO_2 emissions will be in service by approximately four hours into the startup procedure. However, the unit will not achieve its maximum control efficiency for SO_2 until the end of the startup period. The wet scrubber is designed to have an optimal liquid to gas ratio. This ratio is difficult to maintain during the significantly varying exhaust flow conditions during startup. For this reason it will take until the end of the startup before the scrubber meets its peak control efficiency. The SCR system, used for control of NOx emissions, will not be in operation during the startup procedure since the process is ineffective until the equipment reaches a sufficient minimum temperature and the flue gas must be heated to a minimum temperature to minimize the risk of deposition of ammonium sulfates/bisulfate (approximately 600 degrees Fahrenheit). The NOx emissions during the startup will therefore have the potential to be greater than that at normal 100 percent load conditions for brief periods of time. Coal will be introduced to the boiler after approximately four hours into the startup procedure. As the startup procedure continues, the coal input to the boiler will be increased while the distillate fuel oil input to the boiler will be decreased by progressively turning on pulverizers and coal burners. The SCR system will come online approximately thirteen hours into the startup procedure. The startup procedure will end at hour 15, with the boiler experiencing full coal-based operation.

Table 5-12 of the permit application provides the firing and emission rates for both the main boiler and the auxiliary boiler for a 24 hour period during which a startup would occur.

The facility has submitted an evaluation of the emission levels during startup and shutdown in Section 5.4.7.2 of the application. Note that since the shutdown sequence is significantly quicker than the startup sequence, no modeling of shutdown is included since the startup results are conservatively representative of unit shutdowns. The facility is expected to remain in operation for long periods without interruption; however, the number of startups per year will be based on energy demands, plant outages and maintenance.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: NOx, SO_2, CO, PM, $PM_{10,}$ $PM_{2.5}$, VOC, H_2SO_4, and Fluorides. A BACT analysis is required for any emission unit that emits any one of these pollutants.

Georgia Rules for Air Quality Control, Chapter 391-3-1-.02(ttt), requires that any stationary coal fired boiler installed on or after January 1, 2007, capable of producing greater than 25 MW of electricity for sale must apply BACT for control of mercury emissions. Therefore, a BACT evaluation is required for the coal fired boiler for control of mercury emissions.

Coal fired boiler- Background

The coal fired boiler (Emission Unit S1) will be a supercritical pulverized coal boiler with maximum heat input rate of 8,300 MMBtu/hr. The boiler will be rated at 850 MW net output capacity, and will be designed to burn sub-bituminous coal (Powder River Basin, or PRB coal) and as an alternate fuel up to a 50/50 blend of sub-bituminous coal (PRB) and eastern bituminous coal (Illinois #6). Although the boiler will be designed for use of PRB and Illinois #6 coals, it will also have the capability of utilizing bituminous and sub-bituminous coals with equivalent characteristics of PRB and Illinois #6. No. 2 fuel oil will be used for unit startup and for flame stabilization. The maximum heat input rate of the boiler while burning No. 2 fuel oil will be 1,300 MMBtu/hr. The boiler will be used for “base load” electricity generating operations. The boiler will also operate between the operating load range of 40 to 100 percent for extended periods during the shoulder months (spring and fall). Pulverized coal will be combusted in the facility main boiler. Produced steam will be used to drive a steam turbine, which in turn will create electricity through the mechanical energy created by driving the steam turbine generator shaft.

Coal fired boiler – NOx Emissions

Applicant’s Proposal

NOx emissions are a byproduct of coal combustion, and originate from both the coal-bound nitrogen and the nitrogen from the air, used in the combustion process. There are three main formation mechanisms for NOx: thermal NOx, fuel NOx, and prompt NOx. Thermal NOx results from the reaction between oxygen and nitrogen in the combustion air at the high temperatures of combustion. Fuel NOx results from oxidation of coal-bound nitrogen compounds, and depends on the nitrogen content of the coal, the amount of nitrogen evolved at high temperatures during devolatilization, and burner design. Prompt NOx is formed in the early stages of combustion, which cannot be explained by either thermal NOx or fuel NOx. It is presumed to result from the fixation of atmospheric (molecular) nitrogen by carbon fragments that produce OH radical in the flame zone, rather than the fixation of nitrogen in the post-flame gases, as is the case with thermal NOx. Page 4-27 of permit application lists the various parameters that impact NOx emissions.

In Application 17924, the applicant performed the 5-step BACT analysis for the NOx emissions from the coal fired boiler. The brief summary of the applicant’s BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following NOx control technologies for the coal fired boiler:

- Lower-emitting Processes or Practices - Low NOx Burners (LNB)
- Lower-emitting Processes or Practices - Overfire Air (OFA)
- Lower-emitting Processes or Practices - Flue Gas Recirculation (FGR)

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- $SCONO_X$
- Gas Reburning
- Electrocatalytic Oxidation
- Hybrid SNCR/Catalyst Systems
- Pahlman Process
- THERMALONOx
- Oxygen Enhanced Combustion

Please refer to pages 4-28 through 4-32 of the permit application for details on the NOx control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 above and determined that the following control technologies were not technically feasible:
(Please refer to pages 4-32 through 4-35 of the permit application)

- Flue Gas Recirculation (FGR)
- SCONOx
- Electro-Catalytic Oxidation (ECO)
- Pahlman Process
- THERMALONOx
- Oxygen Enhanced Combustion

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has provided a ranking of the NOx control technologies that are technically feasible for this project, as listed in the following table:

- **Table 4-1: NOx Control Technology Ranking**

Control Technique	**Description**	**Control Efficiency[1] (Percent Reduction)**
Overfire Air	Injection of air above main combustion zone	20-30%
Low NOx Burners	Burner design controls mixing of air and fuel to lower combustion temperature	35-55%
Gas Reburning	Injection of reburn fuel and combustion air above the main combustion zone	50-60%
Hybrid SNCR/Catalyst Systems	Hydrid technology that uses SNCR followed by a catalysts that uses NH_3 slip from the SNCR for the SCR process	50-60%
SNCR	Injection of NH_3 or urea in the convective pass zone of the boiler	30-60%
SCR	Injection of NH_3 followed by catalyst bed	70-90%

The applicant has reviewed AP-42, technical publications, the USEPA RACT/BACT/LAER Clearinghouse and vendor information in determination of the control efficiencies. The applicant has determined that SCR in combination with OFA and LNB is the top control technology for NOx emissions. Please refer to pages 4-36 and 4-37 for a detail discussion regarding the effectiveness of NOx control technologies.

[1] Refer email dated April 3, 2009 verifying control efficiency.

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant discussed control effectiveness, energy impacts, environmental impacts and economic impacts for the top control technology and concluded that the use of SCR in combination with OFA and LNB as the BACT control technology for NOx emissions from the coal fired boiler. Please refer to pages 4-37 and 4-38 of the permit application.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for NOx emissions from the coal fired boiler to be the use of SCR in combination with OFA and LNB and a BACT NOx emissions limit of 0.05 lb/mmBtu on a 30-day rolling average. The applicant has proposed to use NOx Continuous Emission Monitor (CEMS) to demonstrate compliance with the limit.

The applicant has discussed/presented variables impacting NOx emissions, CEMS data from the USEPA Clean Air Markets Website, data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse and data from the permits that are in draft stage in demonstration of the BACT limit. Please refer to pages 4-39 and 4-40 of the permit application for the variables impacting NOx emissions. The applicant has provided various charts and graphs analyzing the data obtained from the Clean Air Markets Website on pages 4-42 through 4-56 of the permit application. This analysis discusses different averaging periods (annual, monthly and 24-hr) for NOx emissions and the relationship between the NOx loading to the SCR and the SCR efficiency. Table 4-8 of the permit application lists BACT limits for the facilities for which the permits are either issued or in draft stage. Data from the USEPA RACT/BACT/LAER Clearinghouse and also the draft permits were used in preparation of this table.

EPD Review – NOx Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the NOx BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[2]
- National Coal –Fired Utility Spreadsheet (Accessed August 1, 2008, November 25, 2008 and March 10, 2009)
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Final permit, Preliminary and Final Determination, and Permit Application for Longleaf Energy Associates, LLC, Georgia
- Final Permit, Final Determination, and Permit Application for Desert Rock Energy Company, LLC, New Mexico.
- Draft Permit, Preliminary Determination, and Permit Application for Toquop Energy, LLC, Nevada
- Final Decision issued on January 11, 2008 between Friends of the Chattahoochee, Inc and Sierra Club V. EPD and Longleaf Energy Associates[3]
- USEPA Clean Air Markets Database[4]
- Source Watch website for Coal Power Plant Database information[5]

[2] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

[3] http://www.georgiaair.org/airpermit/downloads/permits/psd/dockets/longleaf/appealdocs/exhibits/011108finaldecision.pdf

[4] http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard

[5] http://www.sourcewatch.org/index.php?title=Portal:Coal_Issues

- National Association of Clean Air Agencies (NACAA) website[6] and Washington Updates by NACAA
- Information about proposed coal plants across the country from Sierra Club website[7]
- AP 42, Fifth Edition, Volume I, Chapter 1.1- Bituminous and Sub-bituminous Coal Combustion
- EPA' Air Pollution Control technology Fact Sheet - SCR[8]
- EPA' Air Pollution Control technology Fact Sheet - SNCR[9]
- Clean Coal technology - Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxide Emissions from Coal-Fired Boilers, An Update of Topical Report Number 9[10]
- Increasing SCR NOx Removal from 85% to 93% at the Duke Power Cliffside Steam Station[11]
- Website of Babcock Power for NOx control technology information[12]

The Division has prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix F. Based on the research performed by the Division and review of the applicant's proposal, the use of SCR in combination with OFA and LNB is the BACT control technology for NOx emissions and 0.05 lb/mmBtu on a 30-day rolling average is the BACT NOx emissions limit. To ensure compliance with the limit, the facility will be required to install a NOx CEMS at the stack outlet.

Conclusion – NOx Control

The BACT selection for the Coal fired boiler is summarized below in Table 4-2:

- **Table 4-2: BACT Summary for the Coal Fired Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Low NOx Burners/Over-fire Air/ Selective Catalytic Reduction	0.05 lb/MMBtu	30 day rolling average	CEMS

6 http://www.4cleanair.org/

7 http://www.sierraclub.org/environmentallaw/coal/plantlist.asp

8 http://www.epa.gov/ttn/catc/dir1/fscr.pdf

9 http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

10 www.netl.doe.gov/cctc

11 http://www.babcockpower.com/index.php?option=brochures&task=viewbrochure&coid=17&broid=62

12 http://www.babcockpower.com/

Coal fired boiler – SO_2 Emissions

Applicant's Proposal

Emissions of sulfur dioxide (SO_2) are generated in fossil fuel fired units from oxidation of sulfur in the fuel source. Uncontrolled emissions of SO_2 are therefore significantly affected by the sulfur content of the fuel, as well as the heating value (Btu/lb) of the fuel.

In Application 17924, the applicant performed the 5-step BACT analysis for the SO_2 emissions from the coal fired boiler. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following SO_2 control technologies for the coal fired boiler:

- Coal Selection
- Coal Refining
- Coal Cleaning
- Wet Scrubber
- Spray Dryer Absorber (Dry Scrubber)
- Circulating Dry Scrubber
- Dry Sorbent Injection

Please refer to pages 4-78 through 4-81 of the permit application for details on the SO_2 control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 above and determined that the following control technologies were not technically feasible:
(Please refer to pages 4-81 through 4-84 of the permit application)

- Coal Refining
- Circulating Dry Scrubber
- Dry Sorbent Injection

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

In this section, the applicant discussed the control effectiveness of the following technically feasible SO_2 control technologies:

- Coal Selection
- Coal Cleaning
- Wet Scrubber
- Spray Dryer Absorber (Dry Scrubber)

Coal Selection is a pre combustion control technique. Sub-bituminous coal (PRB) typically has lower sulfur content than bituminous coal (Illinois #6). The applicant proposed to predominantly use western sub-bituminous coal (PRB) alone or up to a 50/50 blend of sub-bituminous coal (PRB) and bituminous coal (Illinois #6). The applicant stated that providing for the use of bituminous coal is a necessity considering the uncertainty in the future supply of western sub-bituminous coal.

Coal Cleaning is also a pre combustion control technique. Coal cleaning is performed to reduce the coal's sulfur content. Generally, the majority of the sulfur in the coal is organic and is chemically bonded in the molecular structure of the coal itself. This sulfur cannot be removed by physical coal cleaning methods, but a small fraction of the sulfur in the coal is within an iron compound called "pyrite" that can be removed through washing of the coal. The pyritic sulfur content of PRB coal is very low and that further attempts at reduction of sulfur by coal washing is not effective. Illinois #6 coals typically contain a higher pyritic content than PRB coals and coal washing is effective. The applicant has proposed to purchase washed Illinois # 6 coal prior to shipment to the facility.

Wet Scrubber and Spray Dryer Absorber (Dry Scrubber) are post combustion control technologies. The applicant reviewed technical publications, the USEPA RACT/BACT/LAER Clearinghouse and vendor information and determined that Wet Scrubbers are more efficient than Dry Scrubbers. Wet Scrubber also have an added collateral control benefit for secondary pollutants due to more effective capture of secondary acid gases in the flue gas exhaust stream than a dry scrubber, including reactive mercury, hydrogen chloride and fluorides.

To further evaluate the control effectiveness of wet scrubbers versus dry scrubbers, the applicant reviewed the USEPA Clean Air Markets website and the Federal Energy Regulatory Commission (FERC). Data collected from the FERC website included coal quality data for selected sites, including the coal source, sulfur content, higher heating value and quantity of coal obtained in thousands of tons. The applicant used these data, in conjunction with emissions data from the USEPA Clean Air Markets website to produce an evaluation of the SO_2 control efficiency for units using wet scrubbers and dry scrubbers. Pages 4-85 and 4-87 of permit application demonstrates uncontrolled SO_2 emissions calculation and control efficiency calculation.

The applicant used data for the top 10 performing facilities using wet scrubbers and the top 10 facilities using dry scrubbers for calendar years 2006 and 2007 to determine SO_2 control efficiencies. Tables 4-12, 4-13, 4-14, and 4-15 of the permit application represent this data. The average removal for the top 10 dry scrubbers for calendar years 2006 and 2007 was 91.7 percent, while the average for the top 10 wet scrubbers for calendar years 2006 and 2007 was 96.6 percent. Please refer to pages 4-84 through 4-94 of the permit application for a detail discussion regarding the effectiveness of the SO_2 control technologies.

The applicant also described the monthly variability in SO_2 emissions for the top performing emission units in calendars year 2006 and 2007 and it is shown in table 4-18 of the permit application.

Step 4: Evaluating the Most Effective Controls and Documentation

The applicant stated that Wet Scrubber and Dry Scrubber are the top control options for SO_2 control. In this section, the applicant discussed energy impacts, environmental impacts and economic impacts of Dry Scrubber and Wet Scrubber and concluded the use of Wet Scrubber as the top control technology for SO_2 emissions. Please refer to pages 4-95 and 4-96 of the permit application.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for SO_2 emissions from the coal fired boiler to be the use of Wet Scrubber in combination with Coal Selection and Coal Washing of bituminous coal (Illinois #6) and a BACT SO_2 emissions limit of 0.052 lb/mmBtu on a 12-month rolling average, 0.069 lb/mmBtu on a 30-day rolling average, 959 lb/hr on a 3-hour average and a minimum scrubber removal efficiency of 97.5%. The applicant has proposed to use inlet and outlet SO_2 CEMS to demonstrate compliance with the limit.

The applicant has reviewed vendor information and presented/discussed CEMS data from the USEPA Clean Air Markets Website, data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse and data from the permits that are in draft stage in demonstration of the BACT limit. The applicant has provided various charts and graphs analyzing the data obtained from the Clean Air Markets

Website on pages 4-97 through 4-100 of the permit application. This analysis discusses different averaging periods (monthly and 24-hr) for SO_2 emissions. Table 4-20 of the permit application lists BACT limits for the facilities for which the permits are either issued or in draft stage. Data from the USEPA RACT/BACT/LAER Clearinghouse and also the draft permits were used in preparation of this table.

The applicant also calculated controlled SO_2 emissions rates by using low sulfur and high sulfur coals and corresponding estimated control efficiencies in determination of the BACT emissions limit. Please refer to page 4-108 of the permit application.

Table 4-19 of the permit application lists the Wet Scrubber control efficiency data for selected top performing units for calendar years 2003 through 2007. Data from the USEPA Clean Air Markets program and the Federal Energy Regulatory Commission (FERC) was used to estimate control efficiencies. The applicant performed control efficiency demonstration for units with an uncontrolled SO_2 emission rate of less than 2.4 lb/mmBtu, which is shown in Figure 4-14 of the permit application. This analysis demonstrates that 97.5 percent control efficiency is the BACT performance for units burning low-sulfur coal. Also control efficiency demonstration was done for units with an uncontrolled SO_2 emission rate greater than 2.4 lb/mmBtu, which is shown in Figure 4-15 and 4-16 of the permit application. This analysis demonstrates 98.5 percent control efficiency is the BACT performance for units burning high sulfur coals. Pages 4-101 through 4-109 of the permit application discuss control efficiency demonstration.

EPD Review – SO_2 Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the SO_2 BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse
- National Coal –Fired Utility Spreadsheet (Accessed August 1, 2008, November 25, 2008 and March 10, 2009)
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Final permit, Preliminary and Final Determination, and Permit Application for Longleaf Energy Associates, LLC, Georgia
- Final Permit, Final Determination, and Permit Application for Desert Rock Energy Company, LLC, New Mexico.
- Final Permit for LS Power White Pine Energy Associates, LLC, Nevada
- Final Decision issued on January 11, 2008 between Friends of the Chattahoochee, Inc and Sierra Club V. EPD and Longleaf Energy Associates[13]
- USEPA Clean Air Markets Database[14]
- Source Watch website for Coal Power Plant Database information[15]
- National Association of Clean Air Agencies (NACAA) website[16] and Washington Updates by NACAA
- Information about proposed coal plants across the country from Sierra Club website[17]
- AP 42, Fifth Edition, Volume I, Chapter 1.1- Bituminous and Sub-bituminous Coal Combustion

13 http://www.georgiaair.org/airpermit/downloads/permits/psd/dockets/longleaf/appealdocs/exhibits/011108finaldecision.pdf

14 http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard

15 http://www.sourcewatch.org/index.php?title=Portal:Coal_Issues

16 http://www.4cleanair.org/

17 http://www.sierraclub.org/environmentallaw/coal/plantlist.asp

- EPA' Air Pollution Control technology Fact Sheet - Spray-Chamber/Spray-Tower Wet Scrubber[18]
- APTI Virtual Classroom- SI 412C - Lesson 9: Flue Gas Desulfurization (Acid Gas Removal) Systems[19]
- Website for The Institute of Clean Air Companies (ICAC)- Acid Gas/SO_2 Control Technologies[20]
- USGS Coal Quality Database[21]
- Federal Energy Regulatory Commission Database- Electric utility data file that includes information on type of fuel purchase, fuel cost, fuel type, fuel origin, fuel quantity and fuel quality[22]
- Coal Mines of the Powder River Basin[23]
- Coal Information[24]

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix F. Based on the research performed by the Division and review of the applicant's proposal, the use of Wet Scrubber in combination with Coal Selection and Coal Washing of bituminous coal (Illinois #6) is the BACT control technology for SO_2 emissions and 0.052 lb/mmBtu on a 12-month rolling average, 0.069 lb/mmBtu on a 30-day rolling average, 959 lb/hr on a 3-hour rolling average, and a minimum scrubber control efficiency of 97.5% is the BACT emission limit for SO_2. The Division has determined 30-day averaging period for control efficiency demonstration. To ensure compliance with the SO_2 limit and control efficiency, the facility will be required to install a SO_2 CEMS at the inlet and outlet of the Wet Scrubber.

Conclusion – SO_2 Control

The BACT selection for the coal fired boiler is summarized below in Table 4-3:

- **Table 4-3: BACT Summary for the Coal Fired Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SO_2	Wet Limestone Scrubber	0.052 lb/mmBtu	12-month rolling average	Inlet and Outlet CEMS
		0.069 lb/mmBtu	30-day rolling average	
		959 lb/hr	3-hour rolling average	
		Minimum 97.5% removal	30-day rolling average	

[18] http://www.epa.gov/ttncatc1/dir1/fsprytwr.pdf

[19] http://yosemite.epa.gov/oaqps/EOGtrain.nsf/DisplayView/SI_412C_9?OpenDocument

[20] http://www.icac.com/i4a/pages/index.cfm?pageid=3401

[21] http://energy.er.usgs.gov/coalqual.htm

[22] http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html

[23] http://www.wsgs.uwyo.edu/coalweb/WyomingCoal/mines.aspx

[24] http://www.wsgs.uwyo.edu/coalweb/WyomingCoal/default.aspx

Coal fired boiler – PM/PM_{10} Emissions

Applicant's Proposal

The composition and amount of PM emissions from a coal fired boiler is a function of the type of coal used, firing configuration of the boiler, and emission controls in place on the unit. The primary source of PM emissions from the coal fired boilers is a result of incombustible inert matter (ash) in the fuel and condensable substances and acid gases. The primary form of PM emissions from the main boiler will be in the form of PM_{10}, or particles less than 10 microns in diameter, a portion of which will consist of $PM_{2.5}$, or particles less than 2.5 microns in diameter. Another form of PM is termed condensable particulate matter. This is material that is not captured on a filter at stack conditions but could condense in the atmosphere to form an aerosol.

In Application 17924, the applicant performed the 5-step BACT analysis for the PM/PM_{10} emissions from the coal fired boiler. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following PM/PM_{10} control technologies for the coal fired boiler:

- Lower-emitting Process or Practice – Coal Selection
- Lower-emitting Process or Practice – Coal Cleaning
- Fabric Filter Baghouse
- Dry Electrostatic Precipitator (ESP)
- Wet Electrostatic Precipitator (WESP)
- Venturi Scrubber
- Centrifugal Separator
- Advanced Hybrid Particulate Collector
- Agglomerator

Please refer to pages 4-10 through 4-15 of the permit application for details on the PM/PM_{10} control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 above and determined that Advanced Hybrid Particulate Collector is not technically feasible. Please refer to pages 4-15 through 4-18 of the permit application.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

In this section, the applicant discussed the control effectiveness of the following technically feasible PM/PM_{10} control technologies:

- Lower-emitting Process or Practice – Coal Selection
- Lower-emitting Process or Practice – Coal Cleaning
- Fabric Filter Baghouse
- Dry Electrostatic Precipitator (ESP)
- Wet Electrostatic Precipitator (WESP)
- Venturi Scrubber
- Centrifugal Separator
- Agglomerator

Coal Selection is a pre combustion control technique. PRB coal has lower ash content, thereby potentially resulting in lower filterable particulate matter emissions. The applicant proposed to predominantly use western sub-bituminous coal (PRB) alone or up to 50/50 blend of sub-bituminous coal (PRB) and bituminous coal (Illinois #6). The applicant stated that providing for the use of bituminous coal is a necessity considering the uncertainty in the future supply of western sub-bituminous coals.

Coal Cleaning is also a pre combustion control technique. Coal cleaning is considered effective for coals with a significant overburden. Sub-bituminous coals such as PRB coals are typically mined from thick coal seams with little overburden, and PRB coal mining techniques produce a coal product with little rock and noncombustible material. The applicant proposed coal cleaning for the bituminous (Illinois #6) coal.

Fabric Filter Baghouse, ESP, WESP, Venturi Scrubber, Centrifugal Separator and Agglomerator are post combustion control technologies. The applicant reviewed AP-42, technical publications and vendor information in determination of the control effectiveness of these control technologies. Venturi Scrubber, Centrifugal Separator and Agglomerator are not as effective as Baghouse, ESP and WESP. Baghouse, ESP and WESP are capable of achieving 99 percent or more of control efficiency. Baghouses generally are slightly more effective at removal of particulate than ESPs, especially for the finer-particulate-size fractions. Research data indicated that activated carbon is not collected efficiently in an ESP. These particles do not hold an electrostatic charge, which is why they tend to not be collected in an ESP. This is important considering that activated carbon injection is part of the proposed mercury removal process. Please refer to pages 4-18 and 4-20 of the permit application for a detail discussion regarding the effectiveness of PM/PM_{10} control technologies.

Step 4: Evaluating the Most Effective Controls and Documentation

The applicant stated that Fabric Filter Baghouse, ESP and WESP are the top control options for PM/PM_{10} control. Fabric filter baghouse have additional benefits, as it is more effective in the control of metallic (i.e., Mercury, Lead) emissions. The applicant discussed energy impacts, environmental impacts and economic impacts of Fabric Filter Baghouse, ESP and WESP and concluded the use of Fabric Filter Baghouse as the top control technology for PM/PM_{10} emissions. Please refer to pages 4-20 through 4-22 of the permit application.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for PM/PM_{10} emissions from the coal fired boiler to be the use of Fabric Filter Baghouse and a BACT PM/PM_{10} emissions limit of 0.018 lb/mmBtu on a 3-hr average for Total PM_{10} and 0.012 lb/mmBtu on a 24-hr average for Filterable PM. The applicant has proposed to use Methods 201A and 202 excluding ammonium chloride to demonstrate compliance with Total PM_{10} limit and PM CEMS to demonstrate compliance with the Filterable PM limit.

The applicant has reviewed vendor information and data for the similar permitted facilities from USEPA RACT/BACT/LAER Clearinghouse and data from the permits that are in draft stage in demonstration of the BACT limit. Please refer to pages 4-22 and 4-23 and table 4-3 of the permit application.

EPD Review – PM/PM_{10} Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM/PM_{10} BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse
- National Coal –Fired Utility Spreadsheet (Accessed August 1, 2008, November 25, 2008 and March 10, 2009)
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Final permit, Preliminary and Final Determination, and Permit Application for Longleaf Energy Associates, LLC, Georgia

- Final Permit, Final Determination, and Permit Application for Desert Rock Energy Company, LLC, New Mexico.
- Final Permit and Preliminary determination for Duke Energy Carolinas LLC, Cliffside Steam Station, North Carolina
- Final Permit and Statement Of Basis for Santee Cooper (Pee Dee Generating Station), South Carolina
- Final Decision issued on January 11, 2008 between Friends of the Chattahoochee, Inc and Sierra Club V. EPD and Longleaf Energy Associates[25]
- Source Watch website for Coal Power Plant Database information[26]
- National Association of Clean Air Agencies (NACAA) website[27] and Washington Updates by NACAA
- Information about proposed coal plants across the country from Sierra Club website[28]
- AP 42, Fifth Edition, Volume I, Chapter 1.1- Bituminous and Sub-bituminous Coal Combustion

The Division has prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix F. Based on the research performed by the Division and review of the applicant's proposal, the use of Fabric Filter Baghouse is the BACT control technology for PM/PM_{10} emissions and 0.018 lb/mmBtu on a 3-hr average is the BACT emissions limit for Total PM/PM_{10}. The applicant has proposed a BACT emission limit of 0.012 lb/mmBtu for Filterable PM/PM_{10} and provided justification on page 4-22 and 4-23 of the permit application supporting this limit. The Division asked the permit applicant to provide more justification and references in support of the limit and especially regarding introduction of Filterable PM into the flue gas stream due to wet scrubber. The applicant submitted additional information on May 29, 2009. After reviewing this information, the Division agrees with the applicant's proposed BACT emission limit of 0.012 lb/mmBtu for Filterable $PM/PM_{10.}$ The Division has lowered the averaging period from 24-hr to 3-hr rolling for Filterable PM/PM_{10}. To ensure compliance with the Total PM/PM_{10} limit the facility will be required to use Method 5 or Method 17 in conjunction with Method 202 for Total PM/PM_{10}. To ensure compliance with the Filterable PM/PM_{10} limit, the facility will be required to install a PM CEMS at the stack outlet.

Conclusion – PM/PM_{10} Control

The BACT selection for the Coal Fired boiler is summarized below in Table 4-4:

- **Table 4-4: BACT Summary for the Coal Fired Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Total PM/PM_{10}	Fabric Filter Baghouse	0.018 lb/mmBtu	3-hour average	Method 5 or Method 17 in conjunction with Method 202
Filterable PM/PM_{10}	Fabric Filter Baghouse	0.012 lb/mmBtu	3-hour rolling average	CEMS

A Case-by Case Maximum Achievable Control Technology (MACT) analysis is performed for Non-Mercury Metal HAPS. Filterable PM is used as a surrogate for Non-Mercury Metal HAPS. Please refer to Appendix A for the details.

25 http://www.georgiaair.org/airpermit/downloads/permits/psd/dockets/longleaf/appealdocs/exhibits/011108finaldecision.pdf

26 http://www.sourcewatch.org/index.php?title=Portal:Coal_Issues

27 http://www.4cleanair.org/

28 http://www.sierraclub.org/environmentallaw/coal/plantlist.asp

Coal fired boiler – $PM_{2.5}$ Emissions

$PM_{2.5}$ BACT background

On May 16, 2008 EPA finalized regulations to implement the New Source Review (NSR) program for $PM_{2.5}$. The rule finalized several NSR program requirements for sources that emit $PM_{2.5}$ and other pollutants that contribute to $PM_{2.5}$. $PM_{2.5}$ can be emitted directly from a facility or formed secondarily in the atmosphere from emissions of other compounds referred to as precursors. This rule requires NSR permits to address directly emitted $PM_{2.5}$ as well as pollutants responsible for secondary formation of $PM_{2.5}$ as follows:

- Sulfur dioxide (SO_2) – regulated
- Nitrogen oxides (NOx) – regulated unless state demonstrates that NOx emissions are not a significant contributor to the formation of $PM_{2.5}$ for an area(s) in the state
- Volatile organic compounds (VOC) – not regulated unless state demonstrates that VOC emissions are a significant contributor to the formation of $PM_{2.5}$for an area(s) in the state
- Ammonia – not regulated unless state demonstrates that ammonia emissions are a significant contributor to the formation of $PM_{2.5}$ for an area(s) in the state

Direct $PM_{2.5}$ are emitted directly into the air in either solid particle form (filterable) or vapors that can condense in the atmosphere (condensable). This rule defines major source threshold for $PM_{2.5}$ and significant emission rates for direct $PM_{2.5}$ and indirect $PM_{2.5}$ or precursors.

As per EPA's initial guidance, SIP approved states (Georgia) had up to 3 years to revise SIP to include implementation of $PM_{2.5}$ NSR program. Until then, states were allowed to use implementation of PM_{10} program as a surrogate for meeting $PM_{2.5}$ NSR requirements. As per the current guidance, EPA is planning to repeal the PM_{10} Surrogate Policy for SIP-approved states in the immediate future. Therefore, $PM_{2.5}$ BACT analysis is performed for Plant Washington. In Georgia, SO_2 is the only pollutant that is responsible for secondary formation of $PM_{2.5}$.

Applicant's Proposal

The composition and amount of $PM_{2.5}$ emissions from a coal-fired boiler is a function of the type of coal used, firing configuration of the boiler, and emission controls in place on the unit. The source of "direct" $PM_{2.5}$ emissions from coal-fired boilers is a result of incombustible inert matter (ash) in the fuel and condensable organic substances and acid gases. Incombustible inert matter, or ash, will be in a "filterable" form, and can be collected through the same means as collection of larger particle size fractions of filterable PM (i.e. PM_{10}). Condensable $PM_{2.5}$ would not be captured on a filter at stack conditions but could condense in the atmosphere to form an aerosol. Condensable could include emissions of pollutants such as Sulfuric Acid Mist (SAM) and Volatile Organic Compounds (VOCs).

Sources of "indirect" $PM_{2.5}$ emissions, or secondarily formed $PM_{2.5}$ in the atmosphere from emissions of other pollutants, are referred to as precursors. The four primary precursors of $PM_{2.5}$ identified by the EPA in the May 16, 2008 rule included Sulfur Dioxide (SO_2), Nitrogen Oxides (NOx), Volatile Organic Compounds (VOCs), and Ammonia. The Rule further specified that VOCs and Ammonia were not regulated as precursors unless the State demonstrated that they were significant contributors to formation of $PM_{2.5}$ for an area in the State.

The applicant submitted $PM_{2.5}$ BACT analysis on May 14, 2009 as Exhibit F to the permit application. The BACT analysis for the $PM_{2.5}$ emissions from the coal fired boiler addresses "direct" filterable $PM_{2.5}$, "direct" condensable $PM_{2.5}$ and "indirect" precursor emissions.

The brief summary of the applicant's 5-step BACT analysis for $PM_{2.5}$ is as follows:

Direct Filterable $PM_{2.5}$

Step 1: Identify all control technologies

The applicant stated that control technologies identified for PM/PM_{10} in section 4.3.1 of the permit application would also be effective in control of Filterable $PM_{2.5.}$ Previously identified control technologies for PM_{10} for the coal fired boiler are as follows:

- Lower-emitting Process or Practice – Coal Selection
- Lower-emitting Process or Practice – Coal Cleaning
- Fabric Filter Baghouse
- Dry Electrostatic Precipitator (ESP)
- Wet Electrostatic Precipitator (WESP)
- Venturi Scrubber
- Centrifugal Separator
- Advanced Hybrid Particulate Collector
- Agglomerator

Please refer to pages 4-10 through 4-15 of the permit application for details of the control technologies.

The applicant conducted research to identify additional control technologies specific to Filterable $PM_{2.5}$ control. The following are the additional control technologies:

- Coated Fabric or Membrane Fabric Filters
- Electrostatic Fabric Filters
- Membrane Wet ESP

Please refer to pages F-4 and F-5 of Exhibit F of the permit application for details of the control technologies.

Step 2: Eliminate technically infeasible options

In section 4.3.1 of the permit application, the applicant evaluated technical feasibility of all PM/PM_{10} control technologies that are stated in step 1 and determined that Advanced Hybrid Particulate Collector is not technically feasible. Please refer to pages 4-15 through 4-18 of the permit application.

In this section, the applicant stated that control technologies previously identified as feasible for PM/PM_{10} are also feasible control technologies for Filterable $PM_{2.5}$ and further evaluated technical feasibilities of Coated Fabric or Membrane Fabric Filters, Electrostatic Fabric Filters and Membrane Wet ESP. It is determined that all these control technologies are technically feasible.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

In section 4.3.1, the applicant has determined Fabric Filter Baghouse, ESP and WESP are the top control options for PM_{10} control. These are the top controls technologies for $PM_{2.5}$ as well.

In this section, the applicant evaluated control effectiveness of Coated Fabric or Membrane Fabric Filters, Electrostatic Fabric Filters and Membrane Wet ESP. Please refer to pages F-7 and F-8 of Exhibit F. Based on EPA's test data and discussion with vendors, the applicant determined that coated or membrane Fabric Filters will have improved performance in controlling filterable $PM_{2.5}$ emissions over non-coated or non-membrane Fabric Filters. There is not sufficient data available to demonstrate control efficiencies of $PM_{2.5}$ emissions from Electrostatic Fabric Filter and Membrane Wet ESP.

Step 4: Evaluating the Most Effective Controls and Documentation

In section 4.3.1, the applicant discussed energy impacts, environmental impacts and economic impacts of Fabric Filter Baghouse, ESP and WESP and concluded the use of Fabric Filter Baghouse as the top control technology for PM/PM_{10} emissions. Please refer to pages 4-20 through 4-22 of the permit application.

In this section, the applicant determined use of Coated Fabric or Membrane Fabric bags as part of the Fabric Filter Baghouse system as the top control technology for Filterable $PM_{2.5}$ emissions. No energy, economic or environmental impacts would preclude use of this control technology for control of filterable $PM_{2.5}$ emissions.

Direct Condensable $PM_{2.5}$

Direct Condensable $PM_{2.5}$ emissions will be a result of organic condensables (VOCs), acid gases (i.e. sulfuric acid mist), as well as reaction products within the exhaust gas stream (i.e. ammonia and sulfate forming ammonium sulfate). The formation of ammonium compounds through exhaust gas stream reactions will largely be a function of the ammonia slip from the Selective Catalytic Reduction (SCR) system, which will be minimized through proper operation of the SCR system.

The applicant stated that control technologies identified for Condensable PM were addressed in the BACT control technology evaluations for VOC and Sulfuric Acid Mist in Section 4.3.4 and Section 4.3.7 of the permit application. Those technologies identified for control of VOC and Sulfuric Acid Mist would also be effective control technologies for the control of Condensable $PM_{2.5}$. The applicant was not able to find any additional control technologies for emissions of Condensable $PM_{2.5}$.

The applicant evaluated control technologies for the VOC emissions in Section 4.3.4 and concluded use of Good Combustion Controls as the top control option. Evaluation of control technologies for the Sulfuric Acid Mist emissions in Section 4.3.7 indicated use of Duct Sorbent Injection and use of a wet ESP as the top control options. Coal cleaning and coal selection are already an integral part of other BACT analyses (i.e. SO_2) within the application. The most effective controls for control of Condensable $PM_{2.5}$ would include use of Good Combustion Controls, Duct Sorbent Injection and use of a wet ESP.

In Section 4.3.4, the applicant discussed that no energy, environmental, or economic impacts would preclude use of Combustion Controls on the coal fired boiler. The energy, economic, and environmental impacts of use of Duct Sorbent Injection and wet ESP for control of Sulfuric Acid Mist emissions were evaluated in Section 4.3.7. The analysis found that BACT for Sulfuric Acid Mist emissions was use of Duct Sorbent Injection in conjunction with use of a Fabric Filter Baghouse and Wet Scrubber (co-benefit). The Sulfuric Acid Mist BACT emission limit has been determined to be 0.004 lb/mmBtu, and the VOC BACT emission limit has been determined to be 0.003 lb/mmBtu.

The applicant has proposed top control technology for control of Condensable $PM_{2.5}$ emissions to be the use of Good Combustion Controls, Duct Sorbent Injection and use of a Wet Scrubber.

Indirect $PM_{2.5}$ (Precursors)

Indirect $PM_{2.5}$ is $PM_{2.5}$ formed in the atmosphere from emissions of other pollutants that react and form particles or aerosols that analyze as $PM_{2.5}$. These other pollutants are referred to as precursors. The four primary precursors of $PM_{2.5}$ identified by the EPA in the May 16, 2008 Rule included Sulfur Dioxide (SO_2), Nitrogen Oxides (NOx), Volatile Organic Compounds (VOCs), and Ammonia. At present, only SO2 is regulated as a PM2.5 precursor in Georgia.

The applicant evaluated SO_2 and NOx through the BACT process in Section 4.3 of the application. In those sections, a complete technology assessment was provided that determined which control technology would best reduce emissions of these two pollutants.

Section 4.3.2 of the permit application provided in detail a BACT analysis for NOx. The applicant has proposed BACT control technology for NOx emissions from the coal fired boiler to be the use of SCR in combination with OFA and LNB and a BACT NOx emissions limit of 0.05 lb/mmBtu on a 30-day rolling average. By setting this level, the amount of indirect $PM_{2.5}$ created from NOx is also minimized.

Section 4.3.5 of the permit application provided in detail a BACT analysis for SO_2. The applicant has proposed BACT control technology for SO_2 emissions from the coal fired boiler to be the use of Wet Scrubber in combination with Coal Selection and Coal Washing of bituminous coal (Illinois #6) and a BACT SO_2 emissions limit of 0.052 lb/mmBtu on a 12-month rolling average, 0.069 lb/mmBtu on a 30-day rolling average, 959 lb/hr on a 3-hour average and a minimum scrubber removal efficiency of 97.5%. By controlling SO_2 in this manner reduces the potential for $PM_{2.5}$ formation downwind of the facility.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for Filterable $PM_{2.5}$ emissions from the coal fired boiler to be the use of Fabric Filter Baghouse, BACT for control technology for Condensable $PM_{2.5}$ emissions to be the use of Good Combustion Controls, Duct Sorbent Injection (along with the co-benefits of Wet Scrubber), and BACT control technology for $PM_{2.5}$ precursor emissions to be the use of Good Combustion Controls, SCR in conjunction with OFA and LNB, and Wet Scrubber.

The applicant has proposed $PM_{2.5}$ BACT emissions limit of 0.01236 lb/mmBtu on a 3-hr average for Total $PM_{2.5}$ and 0.00636 lb/mmBtu on a 3-hr average for Filterable $PM_{2.5}$. The applicant stated that there is no reference method available for measurement of $PM_{2.5}$ emissions and proposed to use Method 201/201A(including OTM-27) for Filterable $PM_{2.5}$ and Method OTM-28/CTM-39 for Condensable $PM_{2.5.}$ The applicant also stated that since method for measurement of $PM_{2.5}$ from a "wet" stack is still under development, any future proposed testing protocol for the main boiler for $PM_{2.5}$ emissions (following construction of the site) would address and justify use of any promulgated reference methods in the interim period between permit issuance and construction/operation of the source.

The applicant has estimated $PM_{2.5}$ emission rates on page F-13 of Exhibit F.

The applicant reviewed RBLC database for $PM_{2.5}$ emissions and found only 19 facilities that had established $PM_{2.5}$ BACT or LAER emission limits. Table F-6 of Exhibit F of the permit application lists $PM_{2.5}$ emission limits for coal fired boilers from these facilities. None of these units were pulverized coal utility boilers. All three of the units were Circulating Fluidized Bed (CFB) boilers, with two units at the Virginia Electric and Power Company Virginia City Hybrid Energy Center and one unit at the Northern Michigan University Ripley Heating Plant.

The Northern Michigan CFB unit is a 185 MMBtu/hr wood and coal fired unit, with a filterable $PM_{2.5}$ BACT limit of 0.03 lb/MMBtu. However, a footnote for this site indicated that the $PM_{2.5}$ BACT limit was established through use of the PM_{10} surrogacy approach per the 1997 EPA memorandum. Therefore, this limit is not an effective basis of comparison to Plant Washington.

The Virginia City CFB boiler units are 3,132 MMBtu/hr units indicated as using coal and coal refuse. The RBLC listing indicated a Total $PM_{2.5}$ and PM_{10} BACT emission limit of 0.012 lb/mmBtu.

The applicant performed literature review for sources that have undergone a $PM_{2.5}$ BACT analysis and found the Southern Montana Electric Highwood Generating Station in Montana. This proposed site is a 250 MW coal fired facility near Great Falls, Montana using a Circulating Fluidized Bed (CFB) boiler. The original permit application for the site addressed $PM_{2.5}$ BACT through the PM_{10} surrogacy approach. However, through a permit appeal process the Montana Board of Environmental Review issued a decision requiring the applicant to prepare a $PM_{2.5}$ BACT analysis. The applicant prepared a $PM_{2.5}$ BACT analysis, and Montana DEQ issued the revised permit for the site without a numerical $PM_{2.5}$ emission limit. The permit specified control equipment and a future permit modification to establish a numeric emission limit once a reference method is finalized by the EPA. The overall CFB boiler control strategy included limestone injection into the boiler, Selective Non-Catalytic Reduction (SNCR), Hydrated Ash Re-injection (HAR), Activated Carbon Injection, Intrinsically Coated Fabric Filter Baghouse and an enhanced dry scrubber with hydrated lime injection.

EPD Review – $PM_{2.5}$ Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the $PM_{2.5}$ BACT for the coal fired boiler and was able to find only three facilities under USEPA RACT/BACT/LAER Clearinghouse. These are the same facilities that the applicant has found and listed under table F-6 of Exhibit F. The Division performed more research regarding membrane fabric filter bags technology. The effectiveness of a bag filter increases as the particulate cake builds on the fabric and within the interstitial space of the filtering material. The alkaline filter cake also captures mercury and reduces sulfuric acid mist emissions. Membrane fabrics will release virtually all of the filter cake during the cleaning cycle, and may not retain a particulate cake within the fabric's interstitial space after cleaning. This characteristic of a membrane filter may inadvertently reduce the unit's overall control efficiency of acid gases and mercury. The Division contacted EPA's Environmental Technology Verification Program office and vendors for membrane technology (GE Energy and GORE) to find more information regarding how membrane technology effects mercury and acid gases emissions but was not able to find enough information or test data to make any conclusion.

The Division agrees to use Fabric Filter Baghouse as BACT control technology for Filterable $PM_{2.5}$ emissions and use of Good Combustion Controls and Duct Sorbent Injection (along with the co-benefits of a Fabric Filter Baghouse and Wet Scrubber) as the BACT for control technology for Condensable $PM_{2.5}$ emissions. The Division determined that use of Wet Scrubber as BACT control technology for $PM_{2.5}$ precursor emissions as SO_2 is the only pollutant that is responsible for secondary formation of $PM_{2.5}$. The Division does not recommend any membrane technology for Fabric Filter bags at this time, as there is not enough research or data available. The BACT emission limit for Total $PM_{2.5}$ will be 0.0123 lb/mmBtu.

The Division requires the facility to use Method 5 or Method 17 for Filterable portion of Total $PM_{2.5}$ as the applicants proposed test methods would not work in wet stack. The Division anticipates that the more accurate test method for measurement of Filterable $PM_{2.5}$ in wet stack will be finalized and approved prior to startup of the facility. The Division requires the facility to use Method 202 for Condensable portion of Total $PM_{2.5,}$ as Method 202 is the method required for Condensable $PM_{2.5}$ as per Division's Procedures for Testing and Monitoring document.

Conclusion – $PM_{2.5}$ Control

The BACT selection for the Coal Fired boiler is summarized below in Table 4-5:

- **Table 4-5: BACT Summary for the Coal Fired Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Total $PM_{2.5}$	Fabric Filter Baghouse, Good Combustion Controls and Duct Sorbent Injection	0.0123 lb/mmBtu	3-hour average	Method 5 or Method 17 in conjunction with Method 202

Coal fired boiler – CO Emissions

Applicant's Proposal

Carbon monoxide (CO) is a byproduct of the incomplete combustion of carbon in the fuel source. Control of CO is usually accomplished by providing proper fuel residence time and proper combustion conditions (excess air). However, factors to reduce CO emissions, such as addition of excess air to improve combustion, can lead to an increase in NOx emissions. Therefore, an evaluation of the reduction of CO emissions must consider the potential secondary impacts on NOx emissions. CO can be accurately measured in stack gases and be continuously monitored and recorded. Complete combustion of carbon results in carbon dioxide, so the presence of CO indicates incomplete combustion. As such, it would be an effective indicator of incomplete combustion of any type.

In Application 17924, the applicant performed the 5-step BACT analysis for the CO emissions from the coal fired boiler. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified and discussed the following CO control technologies for the coal fired boiler:

- Combustion Controls
- Add-On Controls (Afterburners, Flares, Catalytic Oxidation and External Thermal Oxidation)

Please refer to pages 4-62 through 4-63 of the permit application for details on the CO control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of the control technologies that are stated in step 1 above and determined that the Add-On Controls are not technically feasible.

The use of add-on controls such as flares, afterburners, catalytic oxidation and external thermal oxidation has not been demonstrated in practice for control of CO emissions from coal fired boilers. Flares, afterburners and catalytic oxidation lead to negative secondary environmental impacts, such as increased fuel usage and associated air emissions. Afterburners use large quantities of natural gas and simply convert CO to carbon dioxide. Straight catalytic systems without additional energy would not be technically feasible because the proposed boiler achieves such a high level of heat recovery such that the outlet temperatures of the boiler where a catalyst system could be effectively installed are well below those levels at which a catalyst could effectively operate. Therefore, the only way that a catalyst system could be used would be to derate the heat effectiveness of the boiler to elevate its exhaust temperature. This would, however, be counterproductive in that it would result in a proportional increase in CO emissions as well as all other pollutants to achieve the same amount of power production.

A catalyst system or thermal oxidizer would have to be installed downstream of a particulate matter control device to avoid plugging and blinding of the catalyst. Oxidation catalysts are susceptible to poisoning from high sulfur compounds and can experience fouling in gas streams with high particulate loading. This would also make installation of the oxidation catalyst as an integral part of the SCR system and impractical for a coal fired boiler system. The minimum temperature for use of an oxidation catalyst would be 350 degrees Fahrenheit, based on technical information on BASF and EmeraChem catalysts, and a thermal oxidizer could not effectively function at temperatures less than 1000 degrees Fahrenheit. The exhaust gas temperature from the boiler downstream of the filter is estimated to be less than 350 degrees Fahrenheit. Therefore, use of such systems is deemed technically infeasible.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has determined that Combustion Controls is the only feasible technology for control of CO emissions. Combustion controls, such as the proper combustion chamber and system design and proper operation and maintenance, are demonstrated and proven techniques for the reduction of CO emissions. There are no energy, environmental or economic impacts associated with the implementation of combustion controls.

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant concluded that Combustion Controls as the top control technology for CO control, as there are no energy, environmental, or economic impacts associated with the use of combustion controls.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for CO emissions from the coal fired boiler to be the use of good Combustion Controls and a BACT CO emissions limit of 0.1 lb/mmBtu on a 30-day rolling average and 0.3 lb/mmBtu on a 1-hour basis. The applicant has proposed to use CO CEMS to demonstrate compliance with the limit.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse and data from the permits that are in draft stage in demonstration of the BACT limit (Table 4-9 of permit application). The applicant also reviewed technology supplier literature and discussed this limit with experienced power plant design engineers and multiple equipment suppliers. The applicant discussed variability of CO emissions and provided information to support averaging periods and BACT limits. Please refer pages 4-64 through 4-66 of the permit application.

EPD Review – CO Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the CO BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse
- National Coal –Fired Utility Spreadsheet (Accessed August 1, 2008, November 25, 2008 and March 10, 2009)
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Final permit, Preliminary Determination, and Permit Application for Longleaf Energy Associates, LLC, Georgia
- Source Watch website for Coal Power Plant Database information[29]
- National Association of Clean Air Agencies (NACAA) website[30] and Washington Updates by NACAA
- Information about proposed coal plants across the country from Sierra Club website[31]
- AP 42, Fifth Edition, Volume I, Chapter 1.1- Bituminous and Sub-bituminous Coal Combustion

The Division has prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix F. Based on the research performed by the Division and review of the applicant's proposal, the use of Good Combustion Controls is the BACT control technology for CO emissions and 0.1 lb/mmBtu on a 30-day rolling average and 0.3 lb/mmBtu on a 1-hour average is the BACT emissions limit for CO. To ensure compliance, the facility will be required to install a CO CEMS at the stack outlet.

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[29] http://www.sourcewatch.org/index.php?title=Portal:Coal_Issues

[30] http://www.4cleanair.org/

[31] http://www.sierraclub.org/environmentallaw/coal/plantlist.asp

Conclusion – CO Control

The BACT selection for the Coal Fired Boiler is summarized below in Table 4-6:

- **Table 4-6: BACT Summary for the Coal Fired Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Controls	0.1 lb/mmBtu	30-day rolling average	CEMS
		0.3 lb/mmBtu	1-hour average	

A Case-by Case Maximum Achievable Control Technology (MACT) analysis is performed for Organic HAPS. CO is used as a surrogate for Organic HAPS. Please refer to Appendix A for the details.

Coal fired boiler – VOC Emissions

Applicant's proposal

VOC emissions are generated during the combustion process from incomplete combustion of the fuel, similar to CO emissions. The control of VOC emissions, therefore, is achieved through use of the same good combustion controls that minimize CO emissions, including providing adequate fuel residence time in the combustion chamber, maintaining a high temperature and sufficient oxygen in the combustion zone to ensure complete combustion, and providing adequate turbulence. Excessive VOC emissions could result from below optimal combustion zone conditions. Low levels of VOC emissions are expected from properly operated Coal fired boilers.

In Application 17924, the applicant performed the 5-step BACT analysis for the VOC emissions from the coal fired boiler. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified and discussed the following VOC control technologies for the coal fired boiler:

- Combustion Controls
- Add-On Controls (Afterburners, Flares, Catalytic Oxidation and External Thermal Oxidation)

Please refer to pages 4-70 and 4-71 of the permit application for details on VOC control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of the control technologies that are stated in step 1 above and determined that the Add-On Controls are not technically feasible.

The use of add-on controls such as flares, afterburners, catalytic oxidation and external thermal oxidation has not been demonstrated in practice for control of VOC emissions from Coal fired boilers. Flares, afterburners and catalytic oxidation lead to negative secondary environmental impacts, such as increased fuel usage and associated air emissions. Straight catalytic systems without additional energy would not be technically feasible because the proposed boiler achieves such a high level of heat recovery such that the outlet temperatures of the boiler where a catalyst system could be effectively installed are well below those levels at which a catalyst could effectively operate. Therefore, the only way that a catalyst system could be used would be to derate the heat effectiveness of the boiler to elevate its exhaust temperature. This would, however, be counterproductive in that it would result in a proportional increase in CO emissions as well as all other pollutants to achieve the same amount of power production.

A catalyst system or thermal oxidizer would have to be installed downstream of a particulate matter control device to avoid plugging and blinding of the catalyst. Oxidation catalysts are susceptible to poisoning from high sulfur compounds and can experience fouling in gas streams with high particulate loading. This would also make installation of the oxidation catalyst as an integral part of the SCR system impractical for a coal fired boiler system. The minimum temperature for use of an oxidation catalyst would be 350 degrees Fahrenheit, based on technical information on BASF and EmeraChem catalysts, and a thermal oxidizer could not effectively function at temperatures less than 1000 degrees Fahrenheit. The exhaust gas temperature from the boiler downstream of the filter is estimated to be less than 350 degrees Fahrenheit. Therefore, use of such systems is deemed technically infeasible.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has determined that Combustion Controls is the only feasible technology for control of VOC emissions. There are no energy, environmental or economic impacts associated with the implementation of combustion controls.

The most effective means of reducing VOC emissions is managing the combustion process to achieve complete combustion. Important factors in proper combustion include proper fuel residence time, proper air to fuel ratios in the combustion chamber, and consistent proper temperatures in the combustion chamber. VOC formation will be limited through use of a properly designed combustion chamber with adequate controls to regulate the combustion process. Proper maintenance is also necessary for proper combustion control. Proper operation of fuel feed systems, fans, system dampers, and other equipment will assist in minimization of VOC emissions. However, as stated above, careful consideration is necessary in the process of combustion controls. Since increasing the combustion temperature or oxygen concentration in the combustion chamber would decrease VOC emissions, it would likely increase the formation of thermal NOx, and increase overall NOx emissions.

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant concluded that good Combustion Controls as the top control technology for VOC emissions, as there are no energy, environmental, or economic impacts associated with the use of combustion controls.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for VOC emissions from the coal fired boiler to be the use of good Combustion Controls and a BACT emissions limit of 0.003 lb/mmBtu on a 3-hour average basis. The applicant has proposed to use stack tests (Method 25A minus Method 18) to demonstrate compliance with the VOC limit and to use CO CEMS as a means of continuous demonstration of the VOC limit.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse and data from the permits that are in draft stage in demonstration of the BACT limit (Table 4-11 of permit application). The applicant also reviewed technology supplier literature. The applicant discussed relationship between NOx and VOC emissions and provided explanation to support the proposed BACT emissions limit for VOC. Please refer to page 4-73 of the permit application.

<u>EPD Review – VOC Control</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the VOC BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse
- National Coal –Fired Utility Spreadsheet (Accessed August 1, 2008, November 25, 2008 and March 10, 2009)
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Source Watch website for Coal Power Plant Database information[32]
- National Association of Clean Air Agencies (NACAA) website[33] and Washington Updates by NACAA
- Information about proposed coal plants across the country from Sierra Club website[34]
- AP 42, Fifth Edition, Volume I, Chapter 1.1- Bituminous and Sub-bituminous Coal Combustion

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix F. John W. Turk plant in Arkansas had 0.0036 lb/MMBtu as a BACT emission limit and 0.00078 lb/MMBtu as a MACT emission limit for VOC. VOC was used as a surrogate for all organic HAPS. Division has not found any other Final/draft permit with VOC emission limit as low as 0.00078 lb/MMBtu. The applicant's proposed BACT emission limit of 0.003 lb/MMBtu is similar to other recently issued Final/Draft permits. The applicant also submitted additional information regarding the John W. Turk plant in Arkansas and information supporting proposed VOC limit on May 29, 2009.

Based on the research performed by the Division and review of the applicant's proposal, the use of Good Combustion Controls is the BACT control technology for VOC emissions and 0.003 lb/mmBtu on a 3-hour average is the BACT emissions limit for VOC. To ensure compliance with the limit, the facility will be required to perform stack test (Method 25A minus Method 18) at the stack outlet.

<u>Conclusion – VOC Control</u>

The BACT selection for the Coal Fired Boiler is summarized below in Table 4-7:

- **Table 4-7: BACT Summary for the Coal Fired Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Good Combustion Controls	0.003 lb/mmBtu	3-hour average	Method 25A minus Method 18

<u>Coal fired boiler – Fluoride Emissions</u>

<u>Applicant's Proposal</u>

[32] http://www.sourcewatch.org/index.php?title=Portal:Coal_Issues

[33] http://www.4cleanair.org/

[34] http://www.sierraclub.org/environmentallaw/coal/plantlist.asp

Emissions of Fluoride are generated in fossil fuel fired sources from oxidation of fluorine present in the fuel source. Fluorine is emitted predominantly in the gaseous form of Hydrogen Fluoride (HF). Hydrogen Fluoride can be controlled by the same technologies available for SO_2 emissions.

In Application 17924, the applicant performed the 5-step BACT analysis for the Fluoride emissions from the coal fired boiler. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following Fluoride control technologies for the coal fired boiler:

- Coal Cleaning
- Wet Scrubber
- Spray Dryer Absorber (Dry Scrubber)
- Circulating Dry Scrubber
- Dry Sorbent Injection

Please refer to pages 4-113 through 4-114 of the permit application for details on the Fluoride control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 above and determined that the following control technologies were not technically feasible:
(Please refer to pages 4-114 through 4-115 of the permit application)

- Coal Cleaning
- Circulating Dry Scrubber

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

In this section, the applicant discussed the control effectiveness of the following technically feasible control technologies:

- Wet Scrubber
- Spray Dryer Absorber (Dry Scrubber)
- Sorbent Injection

The applicant reviewed technical publications, the USEPA RBLC and vendor information to determine the control efficiencies of these technically feasible Fluoride control technologies. The applicant estimated removal efficiency of Fluoride similar to SO_2, which is 98.5%. This estimation is based on the assumption that HF is a strong acid and more reactive than SO_2, potentially leading to a higher removal efficiency. The estimated removal efficiency is also based on the information from experienced power plant design engineers. Please refer to page 4-116 of the permit application.

Step 4: Evaluating the Most Effective Controls and Documentation

The applicant selected Wet Scrubber as the top control technology for Fluoride control. Wet Scrubber is also determined as the BACT control technology for SO_2 emissions. The applicant discussed energy impacts, environmental impacts and economic impacts of Wet Scrubber under SO_2 BACT analysis.

Use of Sorbent Injection will provide additional control for Fluoride emissions. Sorbent Injection is determined as the BACT control technology for sulfuric acid mist emissions. Please refer to pages 4-116 of the permit application.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for Fluoride emissions from the coal fired boiler to be the use of Wet Scrubber and a BACT Fluoride emissions limit of 2.17×10^{-4} lb/mmBtu on a 3-hour average. The applicant has proposed to use stack test Method 26 to demonstrate compliance with the limit.

The applicant has reviewed vendor information and data for the similar permitted facilities from USEPA RACT/BACT/LAER Clearinghouse and data from the permits that are in draft stage in demonstration of the BACT limit. Please refer to pages 4-117 through 4-119 and table 4-21 of the permit application.

The applicant also reviewed USGS COALQUAL database and obtained coal analysis data for PRB and Illinois coals. The 90 percent confidence level value for Fluorine for PRB coal was approximately 553 ppm, and for the 50/50 coal blend was approximately 338 ppm. This value gives margin of safety, as the Fluorine limit is the 3-hr average limit that will be demonstrated using one time stack test. The applicant assumed 98.5% of control efficiency for acid gas HF based on information from experienced power plant design engineers and an evaluation of available research data. The applicant performed HF emissions calculation using Fluorine content in the coal and control efficiency. Please refer to pages A-36 and A-41 of Exhibit-A of the permit application for emission calculations.

<u>EPD Review – Fluoride Control</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the Fluoride BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse
- National Coal –Fired Utility Spreadsheet (Accessed August 1, 2008, November 25, 2008 and March 10, 2009)
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Source Watch website for Coal Power Plant Database information[35]
- National Association of Clean Air Agencies (NACAA) website[36] and Washington Updates by NACAA
- Information about proposed coal plants across the country from Sierra Club website[37]
- AP 42, Fifth Edition, Volume I, Chapter 1.1- Bituminous and Sub-bituminous Coal Combustion
- USGS Coalqual Database for Fluorine concentration in coal[38]

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix F. Longview facility in West Virginia had 1.00×10^{-5} lb/MMBtu as BACT emission limit for HF. The Division contacted Mr. Ed Andrews (air permit engineer) from West Virginia DEP on March 23, 2009 to verify the limit for HF. Mr. Ed Andrews confirmed the HF limit and explained that this is very low limit compared to other facilities and the Longview plant when constructed might not be able to comply with the limit.

[35] http://www.sourcewatch.org/index.php?title=Portal:Coal_Issues

[36] http://www.4cleanair.org/

[37] http://www.sierraclub.org/environmentallaw/coal/plantlist.asp

[38] http://energy.er.usgs.gov/coalqual.htm

Based on the research performed by the Division and review of the applicant's proposal, the use of Wet Scrubber is the BACT control technology for Fluoride emissions and 2.17 x 10^{-4} lb/mmBtu on a 3-hour average is the BACT emissions limit for Fluoride. To ensure compliance with the Fluoride limit, the facility will be required to perform Method 26A at the stack outlet.

Conclusion – Fluoride Control

The BACT selection for the coal fired boiler is summarized below in Table 4-8:

- **Table 4-8: BACT Summary for the Coal Fired Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Fluoride	Wet Limestone Scrubber	2.17 x 10^{-4} lb/mmBtu	3-hour average	Method 26A

A Case-by Case Maximum Achievable Control Technology (MACT) analysis is performed for HF. Please refer to Appendix A for the details.

Coal fired boiler – Sulfuric Acid Mist Emissions

Applicant's Proposal

Sulfuric Acid Mist (SAM) is formed in coal fired boilers due to oxidation of SO_2 to SO_3, and subsequent reaction with water vapor to form H_2SO_4. The formation of SAM therefore depends on coal sulfur content and the presence of oxidizing catalysts. Some of the technologies and strategies for control of SAM emissions are similar to those technologies and strategies for control of SO_2 emissions. Factors affecting the generation of SAM include the sulfur content of the fuel used, the alkaline ash content of the fuel used, the SCR catalyst used, the rate of ammonia slip from an SCR control device and the types of control equipment used for control of other pollutants.

In Application 17924, the applicant performed the 5-step BACT analysis for the SAM emissions from the coal fired boiler. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following SAM control technologies for the coal fired boiler:

- Coal Selection
- Coal Refining
- Coal Cleaning
- Low Oxidation Catalyst
- Wet Scrubber
- Spray Dryer Absorber (Dry Scrubber)
- Circulating Dry Scrubber
- Dry Sorbent Injection (in combination with Fabric Filter Baghouse or ESP)
- Sorbent Injection with Wet Scrubber
- Sorbent Injection with Dry Scrubber
- Wet Electrostatic Precipitator (WESP)

Please refer to pages 4-122 through 4-125 of the permit application for details on the SAM control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 above and determined that the following control technologies were not technically feasible:
(Please refer to pages 4-125 through 4-128 of the permit application)

- Coal Refining
- Circulating Dry Scrubber
- Sorbent Injection with Dry Scrubber

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

In this section, the applicant discussed the control effectiveness of the following technically feasible SAM control technologies:

- Coal Selection
- Coal Cleaning
- Low Oxidation Catalyst
- Wet Scrubber
- Spray Dryer Absorber (Dry Scrubber)
- Dry Sorbent Injection (in combination with Fabric Filter Baghouse or ESP)
- Sorbent Injection with Wet Scrubber
- Wet Electrostatic Precipitator (WESP)

Coal Selection is a pre combustion control technique. Coal selection is a demonstrated method for minimizing the amount of sulfur available for SO_2 formation, and therefore SO_3 and H_2SO_4 formation. Sub-bituminous coal (PRB) typically has lower sulfur content than bituminous coal (Illinois #6). The applicant proposed to predominantly use western sub-bituminous coal (PRB) alone or up to a 50/50 blend of sub-bituminous coal (PRB) and bituminous coal (Illinois #6). The applicant stated that providing for the use of bituminous coal is a necessity considering the uncertainty in the future supply of western sub-bituminous coal.

Coal Cleaning is also a pre combustion control technique. Coal cleaning is performed to reduce the coal's sulfur content. Generally, the majority of the sulfur in the coal is organic and is chemically bonded in the molecular structure of the coal itself. This sulfur cannot be removed by physical coal cleaning methods, but a small fraction of the sulfur in the coal is within an iron compound called "pyrite" that can be removed through washing of the coal. The pyritic sulfur content of PRB coal is very low and that further attempts at reduction of sulfur by coal washing is not effective. Illinois #6 coals typically contain a higher pyritic content than PRB coals and coal washing is effective. The applicant has proposed to purchase washed Illinois # 6 coal prior to shipment to the facility.

Wet Scrubber, Dry Scrubber, Low Oxidation Catalyst, Dry Sorbent Injection, Fabric Filter Baghouse, ESP, Sorbent Injection with Wet Scrubber and WESP are the post combustion control technologies. The applicant reviewed technical publications, the USEPA RACT/BACT/LAER Clearinghouse and vendor information to determine control effectiveness of these technologies. Wet scrubber is determined as a BACT control technology for SO_2 emissions, Fabric Filter Baghosue is determined as a BACT control technology for PM/PM_{10} emissions and the facility will be using a Low Oxidation Catalyst in the SCR.

The applicant has provided the following table, which lists control efficiencies of the remaining possible control technologies:

Table 4-9: SAM Control Technology Efficiency

Formation Mechanism/Zone	Control Method	Control Efficiency
Combustion zone generated SO_3	Add Alkaline Adsorbent Into Combustion Zone	66 %
Combustion zone generated SO_3 and SO_2 conversion to SO_3 across SCR catalyst	Add Alkaline Adsorbent Into Duct	90 %
Combustion zone generated SO_3 and SO_2 conversion to SO_3 across SCR catalyst	WESP Downstream of Wet Scrubber	98 %

Please refer to pages 4-128 through 4-130 of the permit application for a detail discussion regarding the effectiveness of the SAM control technologies.

Step 4: Evaluating the Most Effective Controls and Documentation

The applicant stated that WESP and Dry Sorbent Injection are the top control options for SAM control. Coal Selection, Coal Cleaning and use of Wet Scrubber and Fabric Filter Baghouse are already determined as BACT control technologies for other pollutants and will provide control for SAM emissions as well.

In this section, the applicant presented energy impacts, environmental impacts and economic impacts of WESP and Dry Sorbent Injection System. This analysis presumes the use of fabric filter, wet scrubber, use of sub-bituminous (i.e. PRB) coal or a blend of sub-bituminous and bituminous coal (i.e. PRB and Illinois #6), and use of a low oxidation catalyst in the SCR. The economic analysis is performed for Combustion Zone Sorbent Injection, Duct Sorbent Injection, Combustion Zone and Duct Sorbent Injection, WESP, and Sorbent Injection in combination with WESP and they are shown in table 4-23 of the permit application. The applicant rejected WESP control technology due to significant incremental cost effectiveness and average cost effectiveness, and significant energy impact. The applicant concluded the use of Duct Sorbent Injection as the top control technology for SAM emissions. Please refer to pages 4-130 and 4-134 of the permit application.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for SAM emissions from the coal fired boiler to be the use of Duct Sorbent Injection (along with the co-benefits of a Fabric Filter Baghouse and Wet Scrubber) and a BACT SAM emissions limit of 0.004 lb/mmBtu on a 3-hour average. The applicant has proposed to use stack test Method CTM013 to demonstrate compliance with the limit.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse and data from the permits that are in draft stage in demonstration of the BACT limit. Please refer to pages 4-134 and 4-135 and Table 4-24 of the permit application.

EPD Review – Sulfuric acid mist Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the SAM BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse
- National Coal –Fired Utility Spreadsheet (Accessed August 1, 2008, November 25, 2008 and March 10, 2009)
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Source Watch website for Coal Power Plant Database information[39]
- National Association of Clean Air Agencies (NACAA) website[40] and Washington Updates by NACAA
- Information about proposed coal plants across the country from Sierra Club website[41]
- AP 42, Fifth Edition, Volume I, Chapter 1.1- Bituminous and Sub-bituminous Coal Combustion

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix F. Based on the research performed by the Division and review of the applicant's proposal, the use of Duct Sorbent Injection is the BACT control technology for SAM emissions and 0.004 lb/mmBtu on a 3-hour average is the BACT emission limit for SAM. The facility will be required to perform stack test using Method 8. The Division requires the facility to use Method 8 to ensure compliance with the SAM limit, as Method 8 is the method required for SAM as per Division's Procedures for Testing and Monitoring document.

Conclusion – Sulfuric acid mist Control

The BACT selection for the coal fired boiler is summarized below in Table 4-10:

- **Table 4-10: BACT Summary for the Coal Fired Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Sulfuric Acid Mist	Duct Sorbent Injection	0.004 lb/mmBtu	3-hour average	Method 8

[39] http://www.sourcewatch.org/index.php?title=Portal:Coal_Issues

[40] http://www.4cleanair.org/

[41] http://www.sierraclub.org/environmentallaw/coal/plantlist.asp

Coal fired boiler – Mercury Emissions

Applicant's Proposal

Georgia Rules for Air Quality Control, Chapter 391-3-1-.02(2)(ttt), requires that any stationary coal fired boiler installed on or after January 1, 2007, capable of producing greater than 25 MW of electricity for sale must apply Best Available Control Technology (BACT) for control of mercury emissions. Therefore, a BACT evaluation has been conducted for the coal fired boiler for control of mercury emissions.

Mercury is in coal in trace amounts, and is released into the main boiler exhaust flue gas during combustion. Mercury is present in the flue gas stream in one of three different forms, as (1) an elemental mercury vapor, (2) particle-bound mercury, or (3) vapor of an oxidized mercury species (Hg^{2+}), and is typically present in all three forms. The chemical form of the mercury in the flue gas stream can have a significant impact on the effectiveness of the control strategies employed for control of mercury emissions. Elemental mercury is regarded as the most difficult form of mercury to control since it cannot be scrubbed or filtered out. Particulate bound mercury is effectively controlled by particulate matter (PM) control strategies, such as a fabric filter baghouse or ESP. Oxidized mercury is more effectively controlled by gas scrubbing techniques (i.e. wet scrubber). Studies have been found that sorbent injection systems can be designed for effective capture of elemental mercury.

In Application 17924, the applicant performed the 5-step BACT analysis for the Mercury emissions from the coal fired boiler. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following Mercury control technologies for the coal fired boiler:

- Coal Cleaning
- Coal Refining
- Fuel Blending
- Oxidizing Chemicals
- Unburned Carbon Enhancement
- Fabric Filter Baghouse
- ESP
- Wet Scrubber
- Spray Dryer Absorber (Dry Scrubber) in conjunction with Fabric Filter Baghouse
- Selective Catalytic Reduction (SCR)
- Sorbent Injection

Please refer to pages 4-138 through 4-142 of the permit application for details on the Mercury control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 above and determined that the following control technologies were not technically feasible:
(Please refer to pages 4-142 through 4-146 of the permit application)

- Coal Refining
- Unburned Carbon Enhancement
- Spray Dryer Absorber (Dry Scrubber) in conjunction with Fabric Filter Baghouse

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

In this section, the applicant discussed the control effectiveness of the following technically feasible control technologies:

- Coal Cleaning
- Fuel Blending
- Oxidizing Chemicals
- Fabric Filter Baghouse
- ESP
- Wet Scrubber
- Selective Catalytic Reduction (SCR)
- Sorbent Injection

Coal Cleaning and Fuel Blending are pre combustion control techniques. The applicant proposed to use western sub-bituminous coal (PRB) alone or up to a 50/50 blend of sub-bituminous coal (PRB) and bituminous coal (Illinois #6). The applicant has proposed to purchase washed Illinois # 6 coal prior to shipment to the facility.

Fabric Filter Baghouse, Wet scrubber and SCR are determined as a BACT control technologies for PM/PM_{10}, SO_2 and NOx emissions respectively. The applicant has provided the following table, which lists control efficiencies of various control technologies:

Table 4-11: Mercury Capture For Post Combustion Controls for Pulverized Coal Fired Boilers

Post-combustion Control Strategy	Post-combustion Emission Control Device Configuration	Average Mercury Capture by Control Configuration		
		Coal Burned in Pulverized-coal-fired Boiler Unit		
		Bituminous Coal	Subbituminous Coal	Lignite
PM Control Only	CS-ESP	36 %	3%	0 %
	HS-ESP	9 %	6 %	not tested
	FF	90 %	72 %	not tested
	PS	not tested	9 %	not tested
PM Control and Spray Dryer Adsorber	SDA+CS-ESP	not tested	35 %	not tested
	SDA+FF	98 %	24 %	0 %
	SDA+FF+SCR	98 %	not tested	not tested
PM Control and Wet FGD System[(a)]	PS+FGD	12 %	0 %	33%
	CS-ESP+FGD	75 %	29 %	44 %
	HS-ESP+FGD	49 %	29 %	not tested
	FF+FGD	98 %	not tested	not tested

CS-ESP = cold-side electrostatic precipitator (a) Estimated capture across both control devices
HS-ESP = hot-side electrostatic precipitator
FF = fabric filter
PS = particle scrubber
SDA = spray dryer absorber system

Information from the above table is taken from the Control of Mercury Emissions from Coal-fired Electric Utility Boilers (2004), prepared by the USEPA Office of Research and Development. The table illustrates the variability present in mercury control depending on the type of coal and emissions control strategy utilized.

The applicant discussed mercury emission limits and control technologies determined by USEPA under the proposed NESHAP for Electric Utility Units (2004) and under the proposed NSPS regulations. Please refer to pages 4-147 through 4-149 of the permit application.

DOE/NETL initiated a research and development program in the 1990s evaluating mercury-specific control technologies such as sorbent injection and mercury oxidation concepts. The research and development program has been implemented in separate phases, with Phase II of the research and development program completed in 2007. Phase III projects were initiated in 2006 and have not yet been completed. On page 4-149 through 4-158 of permit application, the applicant discussed these studies and presented the results.

From DOE/NETL studies and USEPA's proposed rules for mercury, the applicant determined Sorbent (Powdered Activated Carbon) Injection in conjunction with SCR, Fabric Filter Baghouse and Wet Scrubber as the top control technology for mercury emissions. The majority of these studies involve evaluation of different types of materials (i.e. calcium chloride), different forms of powdered activated carbon (i.e. DARCO Hg-LH), use of coal additives (i.e. KNX), or use of mercury specific oxidation catalysts. The applicant will be using Powdered Activated Carbon or any other material that demonstrates superior performance.

The applicant discussed effectiveness of coal blending and based on DOE/NETL studies concluded that there is not enough evidence to support that coal blending is an effective technique. Please refer to pages 4-158 and 4-159 of the permit application.

Step 4: Evaluating the Most Effective Controls and Documentation

The applicant determined that Sorbent (Powdered Activated Carbon) Injection in conjunction with SCR, Fabric Filter Baghouse and Wet Scrubber as the top level of control for mercury emissions.

In this section, the applicant presented energy impacts, environmental impacts and economic impacts of Sorbent Injection System. Fabric Filter Baghouse, Wet scrubber and SCR are determined as a BACT control technologies for PM/PM_{10}, SO_2 and NOx emissions respectively. Please refer to pages 4-159 and 4-160 of the permit application.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for mercury emissions from the coal fired boiler to be the use of Sorbent Injection in conjunction with SCR, Fabric Filter Baghouse and Wet Scrubber and a BACT mercury emissions limit of 1.68×10^{-6} lb/mmBtu or 15×10^{-6} lb/MW-hr on a 12-month rolling average. The applicant has proposed to use mercury CEMS to demonstrate compliance with the limit.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse and data from the permits that are in draft stage in demonstration of the BACT limit. Please refer to Table 4-27 of the permit application.

The applicant also reviewed USGS COALQUAL database and obtained coal analysis data for PRB and Illinois coals. The 95 percent confidence level value for Mercury for PRB coal was approximately 0.11 ppm. This value represents the 12-month average Mercury concentration in the coal as the emissions limit is an annual average limit that needs to be monitored on a continuous basis. Using this concentration value, the uncontrolled emissions rate of mercury in the coal is 1.02×10^{-5} lb/mmBtu. Please refer to page A-37 of Exhibit-A of the permit application for emission calculation. The proposed BACT emissions limit of 1.68×10^{-6} lb/mmBtu corresponds to a control efficiency of 84%. This control efficiency is the efficiency that needs to be achieved on a 12-month average basis. Based on the data that was presented for the BACT analysis, the estimated control efficiency for mercury when firing PRB coal can be up to 93%. This efficiency represents short-term efficiency and there is no data that currently exists for any long-term period.

EPD Review – Mercury Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the Mercury BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse
- National Coal –Fired Utility Spreadsheet (Accessed August 1, 2008, November 25, 2008 and March 10, 2009)
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Final permit, Preliminary and Final Determination, and Permit Application for Longleaf Energy Associates, LLC, Georgia
- Final Decision issued on January 11, 2008 between Friends of the Chattahoochee, Inc and Sierra Club V. EPD and Longleaf Energy Associates[42]
- Source Watch website for Coal Power Plant Database information[43]
- National Association of Clean Air Agencies (NACAA) website[44] and Washington Updates by NACAA
- Information about proposed coal plants across the country from Sierra Club website[45]
- AP 42, Fifth Edition, Volume I, Chapter 1.1- Bituminous and Sub-bituminous Coal Combustion
- USGS Coal Quality Database for Mercury concentration in coal[46]
- USEPA white paper - Control of Mercury Emissions from Coal-Fired Electric Utility Boilers[47]
- Additional mercury controls (Regenerative Activated Coke Technology, Trona Injection, etc.)[48]

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix F. Mid-Michigan Energy, LLC that is currently being reviewed by Michigan Department of Environmental Quality, Air Quality Division (Michigan DEQ) submitted a letter dated January 12, 2009 to Michigan DEQ proposing a mercury limit of 13×10^{-6} lb/MWhr while firing sub-bituminous coal as a fuel in the boilers[49]. This provides substantiation to lower the current proposed mercury limit from 15×10^{-6} lb/MWhr to 13×10^{-6} lb/MWhr while firing sub-bituminous coal. Based on the research performed by the Division and review of the applicant's proposal, the use of Activated Carbon Injection in conjunction with SCR, Fabric Filter Baghouse and Wet Scrubber is the BACT control technology for Mercury emissions and 13×10^{-6} lb/MW-hr on a 12-month rolling average is the BACT emissions limit for mercury. To ensure compliance with the limit, the facility will be required to install a Mercury CEMS at the stack outlet.

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42 http://www.georgiaair.org/airpermit/downloads/permits/psd/dockets/longleaf/appealdocs/exhibits/011108finaldecision.pdf

43 http://www.sourcewatch.org/index.php?title=Portal:Coal_Issues

44 http://www.4cleanair.org/

45 http://www.sierraclub.org/environmentallaw/coal/plantlist.asp

46 http://energy.er.usgs.gov/coalqual.htm

47 http://www.epa.gov/ttnatw01/utility/hgwhitepaperfinal.pdf

48 The Division researched the internet on additional mercury control technologies, such as Regenerative Activated Coke Technology and Trona Injection, but could find any vendors that will make it commercially available.

49 Letter dated January 12, 2009, Mid-Michigan Energy, LLC to Michigan Department of Environmental Quality, Air Quality Division

Conclusion – Mercury Control

The BACT selection for the coal fired boiler is summarized below in Table 4-12:

- **Table 4-12: BACT Summary for the Coal Fired Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Mercury	Activated Carbon Injection in Conjunction With SCR/Fabric Filter Baghouse/Wet Scrubber	13 x 10^{-6} lb/MW-hr (gross)	12-month rolling average	CEMS

A Case-by Case Maximum Achievable Control Technology (MACT) analysis is performed for Mercury. Please refer to Appendix A for the details.

Coal fired boiler – Lead Emissions

Emissions of Lead (Pb) are generated from fossil fuel combustion sources from trace amounts of Pb present in the fuel ash. During the combustion process, lead can be vaporized and later condensed or adsorbed by the fly ash suspended in the flue gas. As such, Pb is emitted as PM from a PC fired boiler. Therefore, technologies available for the control of Pb emissions are the same technologies available for the control of PM emissions.

The applicant has elected to propose a lead PSD avoidance limit for the coal fired boiler of 1.60 x 10^{-5} lb/MMBtu. Compliance with this limit will maintain facility wide lead emissions to below the lead PSD significance threshold of 0.60 ton/yr. Therefore, BACT analysis is not required for Lead.

The applicant has performed calculations using data obtained from the coalqual database. The uncontrolled Lead emissions are 1.6 x 10^{-3} lb/MMBtu. Using 99% control efficiency of Fabric Filter Baghouse which controls Lead emissions, the controlled emissions are 1.60 x 10^{-5} lb/mmBtu. To ensure compliance, the facility will be required to perform stack test (Method 29) at the stack outlet.

Auxiliary Boiler - Background

The Auxiliary Boiler (Emission Unit S45) will be an ultra low sulfur diesel-fired boiler with a maximum heat input capacity of 240 MMBtu/hr. The boiler operating hours will be limited to a total of 876 hours per twelve consecutive months. The auxiliary boiler will be used during startup and shutdown operations of the main coal fired boiler.

Auxiliary boiler – NOx Emissions

Applicant's Proposal

NO_x is a byproduct of the combustion process and is formed by the oxidation of nitrogen contained in the fuel in the combustion process. Additionally, NO_x can be formed when elemental nitrogen and elemental oxygen are subjected to high temperatures in the combustion process. Temperature, residence time, excess air and nitrogen availability impact the generation of NO_x.

In Application 17924, the applicant performed the 5-step BACT analysis for the NOx emissions from the auxiliary boiler. The summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified the following NOx control technologies for the auxiliary boiler:
(Please refer to page 4-172 of the permit application)

- Combustion Controls (Fuel Residence Time, Air to Fuel Ratio and Temperature)
- Low NOx Burner
- Flue Gas Recirculation
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- $SCONO_X$

Step 2: Eliminate technically infeasible options

The use of SCR, SNCR, or SCONOx has not been demonstrated in practice for control of NOx emissions from auxiliary boilers. These controls require steady-state operations, which do not occur for units that are used for minimized time periods, such as auxiliary boilers. Hence SCR, SNCR and SCONOx are not technically feasible options. Combustion controls, such as the proper combustion chamber with low NOx burners, in conjunction with flue gas recirculation are demonstrated and proven techniques for the reduction of NOx emissions.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

Combustion controls including Low NOx Burner in conjunction with Flue Gas Recirculation is the only feasible technology for control of NO_x emissions. Combustion controls are designed to optimize the emissions of NO_x from an auxiliary boiler. Combustion controls are now a standard part of the design process of a boiler. There are no energy, environmental or economic impacts associated with the implementation of combustion controls.

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant concluded that the use of Combustion Controls including Low NOx Burner in conjunction with Flue Gas Recirculation as the BACT control technology for NOx emissions from the auxiliary boiler.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for NOx emissions from the auxiliary boiler to be the use of Combustion Controls including Low NOx Burner in conjunction with Flue Gas Recirculation and a BACT NOx emissions limit of 0.1 lb/mmBtu.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse in demonstration of the BACT limit (Table 4-29 of permit application).

EPD Review – NOx Control

The Division has performed independent research of the NOx BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix G. Based on the research performed by the Division and review of the applicant's proposal, the use of Combustion Controls including Low NOx Burner in conjunction with Flue Gas Recirculation is the BACT control technology for NOx emissions and 0.1 lb/mmBtu is the BACT NOx emissions limit. To ensure compliance with the limit, the facility will be required to perform stack test Method 7 or 7E at the stack outlet.

Conclusion – NOx Control

The BACT selection for the Auxiliary Boiler is summarized below in Table 4-13:

- **Table 4-13: BACT Summary for the Auxiliary Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Combustion Controls – Low NOx Burner and Flue Gas Recirculation	0.1 lb/MMBtu	3-hour average	Method 7 or 7E

Auxiliary boiler – SO_2 Emissions

Applicant's Proposal

SO_2 emissions are generated during a combustion process from the combustion of sulfur contained in the fuel. Control of SO_2 emissions is primarily controlled through the sulfur content in the fuel. Combustion of light distillate oil (diesel fuel) will result in lower SO_2 emissions.

In Application 17924, the applicant performed the 5-step BACT analysis for the SO_2 emissions from the auxiliary boiler. The summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified Fuel Selection, Wet Scrubber, Dry Scrubber and Sorbent Injection as the SO_2 control technologies for the auxiliary boiler. The applicant stated that the control technologies for auxiliary boiler are similar to those discussed for coal fired boiler.

Step 2: Eliminate technically infeasible options

The applicant reviewed all control technologies and identified that the low-sulfur fuel, Wet Scrubber and Dry Scrubber are the technically feasible control technologies.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant stated that use of any add on control device to auxiliary boiler is not effective as the auxiliary boiler will operate for only 876 hrs/yr. The use of ultra low sulfur fuel is the top control technology for the auxiliary boiler.

Step 4: Evaluating the Most Effective Controls and Documentation

There are no energy, environmental, or economic impacts associated with the use of ultra low sulfur diesel fuel.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for SO_2 emissions from the auxiliary boiler to be the use of ultra low sulfur fuel oil and a BACT SO_2 emissions limit of 0.05 lb/mmBtu. The applicant has proposed fuel certification to demonstrate compliance with the limit.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse in demonstration of the BACT limit (Table 4-32 of permit application).

EPD Review – SO_2 Control

The Division has performed independent research of the SO_2 BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix G. Based on the research and emission calculations performed by the Division and review of the applicant's proposal, the use of ultra low sulfur fuel is the BACT control technology for SO_2 emissions and 0.0017 lb/mmBtu is the BACT SO_2 emissions limit. To ensure compliance with the limit, the facility will be required to use ultra low sulfur fuel that has a maximum sulfur content of 15 ppm (0.0015% by weight) and need to keep copies of fuel certification.

Conclusion – SO_2 Control

The BACT selection for the Auxiliary Boiler is summarized below in Table 4-14:

- **Table 4-14: BACT Summary for the Auxiliary boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SO_2	Ultra low sulfur fuel oil	0.0017 lb/MMBtu	3-hour average	Fuel oil certification

Auxiliary boiler – PM/PM_{10} Emissions

Applicant's Proposal

PM emissions from oil fired boilers primarily consist of particles resulting from the incomplete combustion of the oil. PM emissions can be affected by the grade of fuel oil fired in a boiler. Combustion of lighter distillate oil results in lower PM formation than combustion of heavier residual oils.

In Application 17924, the applicant performed the 5-step BACT analysis for the PM/PM_{10} emissions from the auxiliary boiler. The summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified the following PM/PM_{10} control technologies for the auxiliary boiler:
(Please refer to pages 4-164 through 4-167 of the permit application)

- Fuel Selection
- Fabric Filter Baghouse
- Dry Electrostatic Precipitator (ESP)
- Wet Electrostatic Precipitator (WESP)

Step 2: Eliminate technically infeasible options

The applicant has determined that all control technologies listed in step 1 above are technically feasible for controlling PM/PM_{10} emissions from fuel oil fired boilers.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

Since the primary purpose of the auxiliary boiler is for startup and shutdown of the PC boiler, its operational schedule generally preclude the use of any control systems.

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant discussed energy, environmental and economic impact of Fabric Filter Baghouse, ESP and WESP. The applicant has determined that the use of PM control technologies on a light distillate fuel oil fired boiler would lead to a significant negative economic impact.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for PM/PM_{10} emissions from the auxiliary boiler to be the use of ultra low sulfur fuel oil and a BACT Total PM/PM_{10} emissions limit of 0.024 lb/mmBtu and Filterable PM_{10} limit of 0.014 lb/mmBtu.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse in demonstration of the BACT limit (Table 4-28 of permit application).

EPD Review – PM/PM_{10} Control

The Division has performed independent research of the PM/PM_{10} BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix G. Based on the research and emission calculations performed by the Division and review of the applicant's proposal, the use of ultra low sulfur fuel oil is the BACT control technology for PM/PM_{10} emissions and 0.024 lb/mmBtu is the BACT Total PM/PM_{10} emissions limit and 0.014 lb/mmBtu is the Filterable PM/PM_{10} emissions limit. To ensure compliance with the limit, the facility will be required to perform stack test Method 5 or 17 in conjunction with Method 202.

Conclusion – PM/PM_{10} Control

The BACT selection for the Auxiliary Boiler is summarized below in Table 4-15:

- **Table 4-15: BACT Summary for the Auxiliary Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Total PM/PM_{10}	Ultra low sulfur fuel oil	0.024 lb/MMBtu	3-hour average	Method 5 or 17 in conjunction with Method 202
Filterable PM/PM_{10}	Ultra low sulfur fuel oil	0.014 lb/MMBtu	3-hour average	Method 5 or 17

A Case-by Case Maximum Achievable Control Technology (MACT) analysis is performed for Inorganic Metal HAPS. Filterable PM is used as a surrogate for Inorganic Metal HAPS. Please refer to Appendix A for the details.

Auxiliary Boiler – $PM_{2.5}$ Emissions

Applicant's Proposal

$PM_{2.5}$ emissions from oil fired boilers can be affected by the grade of fuel oil fired in a boiler. PM emissions from oil fired boilers primarily consist of particles resulting from the incomplete combustion of the oil. Combustion of lighter distillate oil results in lower PM formation than combustion of heavier residual oils.

The source of "direct" $PM_{2.5}$ emissions from the auxiliary boiler is a result of incomplete combustion of the oil and condensable organic substances and acid gases. Incombustible inert matter will be in a "filterable" form, and can be controlled through the same means as collection of larger particle size fractions of filterable PM (i.e. PM_{10}). Condensable $PM_{2.5}$ would not be captured on a filter at stack conditions but could condense in the atmosphere to form an aerosol. Condensable could include emissions of pollutants such as Sulfuric Acid Mist (SAM) and Volatile Organic Compounds (VOCs). The applicant has performed BACT analysis for SAM and VOCs in Section 4.4 of the permit application.

In Exhibit F of the permit application 17924, the applicant performed the BACT analysis for $PM_{2.5}$ emissions from the auxiliary boiler. This BACT analysis addresses the major constituents of $PM_{2.5}$, including "direct" filterable $PM_{2.5}$, "direct" condensable $PM_{2.5}$, and "indirect" precursor emissions.

The brief summary of the applicant's 5-step BACT analysis for $PM_{2.5}$ is as follows:

Direct Filterable $PM_{2.5}$

Step 1: Identify all control technologies

The applicant stated that control technologies identified for Filterable PM_{10} in section 4.4.1 of the permit application would also be effective in control of Filterable $PM_{2.5.}$ Previously identified control technologies for PM_{10} for the auxiliary boiler are as follows:

- Fuel Selection
- Fabric Filter Baghouse
- Dry Electrostatic Precipitator (ESP)
- Wet Electrostatic Precipitator (WESP)

Please refer to pages 4-164 through 4-167 of the permit application for details of the control technologies.

The applicant also stated additional technologies that were identified in section F.2 of Exhibit F, such as Coated Fabric or Membrane Fabric Filters, Electrostatic Fabric Filters and Membrane Wet ESP.

Step 2: Eliminate technically infeasible options

In section 4.4.1 of the permit application, the applicant evaluated technical feasibility of all control technologies.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

Since the primary purpose of the auxiliary boiler is for startup and shutdown of the PC boiler, its operational schedule generally preclude the use of any control systems.

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant has determined that the use of $PM_{2.5}$ control technologies on a light distillate fuel oil fired boiler would lead to a significant negative economic impact.

The applicant has proposed BACT control technology for Filterable $PM_{2.5}$ emissions from the auxiliary boiler to be the use of ultra low sulfur fuel oil (if commercially available).

Direct Condensable $PM_{2.5}$

Direct Condensable $PM_{2.5}$ emissions will be a result of organic condensables (VOCs), acid gases (i.e. sulfuric acid mist), as well as reaction products within the exhaust gas stream.

The applicant stated that control technologies identified for Condensable PM were addressed in the BACT control technology evaluations for VOC and Sulfuric Acid Mist in Section 4.4.4 and Section 4.4.6 of the permit application. Those technologies identified for control of VOC and Sulfuric Acid Mist would also be effective control technologies for the control of Condensable $PM_{2.5}$. The applicant was not able to find any additional control technologies for emissions of Condensable $PM_{2.5}$.

The applicant evaluated control technologies for the VOC emissions in Section 4.4.4 and concluded use of Good Combustion Controls as the top control option. Evaluation of control technologies for the Sulfuric Acid Mist emissions in Section 4.4.6 indicated use of ultra low sulfur fuel oil as the top control option. The applicant stated that use of any add on control device to auxiliary boiler is not effective as the auxiliary boiler will operate for only 876 hrs/yr and it's primary purpose is for startup and shutdown of the main boiler. The applicant has proposed top control technology for control of Condensable $PM_{2.5}$ emissions to be the use of Good Combustion Controls and use of ultra low sulfur fuel oil (if commercially available).

Indirect $PM_{2.5}$ (Precursors)

Indirect $PM_{2.5}$ is $PM_{2.5}$ formed in the atmosphere from emissions of other pollutants that react and form particles or aerosols that analyze as $PM_{2.5}$. These other pollutants are referred to as precursors. The four primary precursors of $PM_{2.5}$ identified by the EPA in the May 16, 2008 Rule included Sulfur Dioxide (SO_2), Nitrogen Oxides (NOx), Volatile Organic Compounds (VOCs), and Ammonia. The Rule specified that VOCs and Ammonia were not regulated as precursors unless the State demonstrated that they were significant contributors to formation of $PM_{2.5}$ for an area in the State. Significant emissions of ammonia is not be expected from the auxiliary boiler.

The applicant evaluated SO_2, NOx and VOC through the BACT process in Section 4.4 of the application.

Section 4.4.2 of the permit application provided in detail a BACT analysis for NOx. The applicant has proposed BACT control technology for NOx emissions from the auxiliary boiler to be the use of Combustion Controls including Low NOx Burner in conjunction with Flue Gas Recirculation.

Section 4.4.5 of the permit application provided in detail a BACT analysis for SO_2. The applicant has proposed BACT control technology for SO2 emissions from the auxiliary boiler to be the use of ultra low sulfur fuel oil.

Section 4.4.4 of the permit application provided in detail a BACT analysis for VOC. The applicant has proposed BACT control technology for VOC emissions from the auxiliary boiler to be the use of good Combustion Controls.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for Filterable $PM_{2.5}$ emissions from the auxiliary boiler to be the use of ultra low sulfur fuel oil, BACT control technology for Condensable $PM_{2.5}$ emissions to be the use of Good Combustion Controls and ultra low sulfur fuel oil and BACT control technology for $PM_{2.5}$ precursor emissions to be the use of Good Combustion Controls including Low NOx Burner in conjunction with Flue Gas Recirculation and ultra low sulfur fuel oil.

The applicant has proposed $PM_{2.5}$ BACT emissions limit of 0.012 lb/mmBtu for Total $PM_{2.5.}$

The applicant has estimated $PM_{2.5}$ emission rates on page F-23 of Exhibit F.

The applicant reviewed RBLC database for $PM_{2.5}$ emissions and found only one facility. The auxiliary boiler for the Virginia Electric and Power Company Virginia City Hybrid Energy Center is the only oil fired unit with a Total $PM_{2.5}$ BACT emission limit of 0.024 lb/mmBtu. The same boiler has Total PM_{10} BACT emission limit of 0.024 lb/mmBtu.

The applicant performed literature review for sources that have undergone a $PM_{2.5}$ BACT analysis for auxiliary boiler but was not able to find any information.

<u>EPD Review – $PM_{2.5}$ Control</u>

The Division has performed independent research of the $PM_{2.5}$ BACT for the auxiliary boiler and was able to find only one facility (Virginia Electric and Power Company) under USEPA RACT/BACT/LAER Clearinghouse. This is the same facility that the applicant has found. The Division agrees with the applicant's proposal to use ultra low sulfur fuel oil as the BACT control technology for Filterable $PM_{2.5}$ emissions and use of Good Combustion Controls and ultra low sulfur fuel oil as the BACT control technology for Condensable $PM_{2.5}$ emissions. The Division determined that use of ultra low sulfur fuel oil as BACT control technology for $PM_{2.5}$ precursor emissions as SO_2 is the only pollutant that is responsible for secondary formation of $PM_{2.5}$.The BACT emission limit for Total $PM_{2.5}$ will be 0.012 lb/mmBtu.

To ensure compliance with the Total $PM_{2.5}$ limit the facility will be required to use Method 5 or Method 17 for filterable portion of Total $PM_{2.5}$ until the Director approves a test Method for measurement of Filterable $PM_{2.5}$ and Method 202 for Condensable portion of Total $PM_{2.5}$. The Division understands that there is no approved test method for measurement of Filterable $PM_{2.5}$ in stack and Method 5 or Method 17 will result into higher Filterable $PM_{2.5}$ measurement.

The Division requires the facility to use Method 5 or Method 17 for Filterable portion of Total $PM_{2.5}$. The Division anticipates that the more accurate test method for measurement of Filterable $PM_{2.5}$ will be finalized and approved prior to startup of the facility. The Division requires the facility to use Method 202 for Condensable portion of Total $PM_{2.5}$, as Method 202 is the method required for Condensable $PM_{2.5}$ as per Division's Procedures for Testing and Monitoring document.

Conclusion – $PM_{2.5}$ Control

The BACT selection for the Auxiliary Boiler is summarized below in Table 4-16:

- **Table 4-16: BACT Summary for the Auxiliary Boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Total $PM_{2.5}$	Good Combustion Controls and ultra low sulfur fuel oil	0.012 lb/mmBtu	3-hour average	Method 5 or Method 17 in conjunction with Method 202

Auxiliary Boiler – CO Emissions

Applicant's Proposal

CO is a byproduct of the incomplete combustion of carbon in the fuel source. Control of CO is usually accomplished by providing proper fuel residence time and proper combustion conditions. However, factors to reduce CO emissions, such as addition of excess air to improve combustion, can lead to a resultant increase in NOx emissions through thermal formation of NOx emissions. Therefore, any evaluation of the reduction of CO emissions must consider the potential secondary impacts in reductions of CO emissions.

In Application 17924, the applicant performed the 5-step BACT analysis for the CO emissions from the auxiliary boiler. The summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified Combustion Controls and Add on Controls (afterburners, flares, catalytic oxidation and external thermal oxidation) as the CO control technologies for the auxiliary boiler. Please refer to page 4-176 of the permit application.

Step 2: Eliminate technically infeasible options

The applicant stated that the use of add-on controls for control of CO emissions for the auxiliary boiler is not technically feasible. Use of add-on controls, such as flares, afterburners, catalytic oxidation and external thermal oxidation, has not been demonstrated in practice for control of CO emissions from auxiliary boilers. Combustion controls, such as the proper combustion chamber and system design, and proper operation and maintenance, are demonstrated and proven techniques for the reduction of CO emissions. Combustion controls are considered a demonstrated technology for auxiliary boiler CO emissions controls and therefore considered technically feasible under the BACT evaluation process.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has determined that good Combustion Controls is the only feasible control technology for CO emissions. There are no energy, environmental or economic impacts associated with the implementation of combustion controls.

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant concluded that the use of good Combustion Controls as the top control technology for CO emissions from the auxiliary boiler as there are no energy, environmental or economic impacts associated with the implementation of combustion controls.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for CO emissions from the auxiliary boiler to be the use of good Combustion Controls and a BACT CO emissions limit of 0.04 lb/mmBtu.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse in demonstration of the BACT limit (Table 4-30 of permit application).

EPD Review – PM/PM_{10} Control

The Division has performed independent research of the CO BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix G. Based on the research and emission calculations performed by the Division and review of the applicant's proposal, the use of Good Combustion Controls is the BACT control technology for CO emissions and 0.04 lb/mmBtu is the BACT CO emissions limit. To ensure compliance with the limit, the facility will be required to perform stack test Method 10.

Conclusion – CO Control

The BACT selection for the auxiliary boiler is summarized below in Table 4-17:

- **Table 4-17: BACT Summary for the Auxiliary boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Controls	0.04 lb/MMBtu	3-hour average	Method 10

A Case-by Case Maximum Achievable Control Technology (MACT) analysis is performed for Organic HAPS. CO is used as a surrogate for Organic HAPS. Please refer to Appendix A for the details.

Auxiliary boiler – VOC Emissions

Applicant's Proposal

VOC emissions are generated during a combustion process from incomplete combustion of the fuel, similar to CO emissions. Control of VOC emissions, therefore, is completed in the same manner as that of CO emissions, through providing adequate fuel residence time in the combustion chamber and maintaining a high temperature and sufficient oxygen in the combustion zone to ensure complete combustion. Excessive VOC emissions could result from below optimal combustion zone conditions. Low levels of VOC emissions are expected from properly operated boilers.

In Application 17924, the applicant performed the 5-step BACT analysis for the VOC emissions from the auxiliary boiler. The summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant has identified Combustion Controls and Add on Controls (afterburners, flares, catalytic oxidation and external thermal oxidation) as the VOC control technologies for the auxiliary boiler. Please refer to page 4-179 of the permit application.

Step 2: Eliminate technically infeasible options

The applicant stated that the use of add-on controls for control of VOC emissions for the auxiliary boiler is not technically feasible. Use of add-on controls, such as flares, afterburners, catalytic oxidation and external thermal oxidation, has not been demonstrated in practice for control of VOC emissions from auxiliary boilers. Combustion controls, such as the proper combustion chamber and system design, and proper operation and maintenance, are demonstrated and proven techniques for the reduction of VOC emissions. Combustion controls are considered a demonstrated technology for auxiliary boiler VOC emissions controls and therefore considered technically feasible under the BACT evaluation process.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has determined that good Combustion Controls is the only feasible technology for VOC emissions. There are no energy, environmental or economic impacts associated with the implementation of combustion controls.

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant concluded that the use of good Combustion Controls as the top control technology for VOC emissions from the auxiliary boiler as there are no energy, environmental or economic impacts associated with the implementation of combustion controls.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for VOC emissions from the auxiliary boiler to be the use of good Combustion Controls and a BACT VOC emissions limit of 0.003 lb/mmBtu.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse in demonstration of the BACT limit (Table 4-31 of permit application).

<u>EPD Review – VOC Control</u>

The Division has performed independent research of the VOC BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix G. Based on the research and emission calculations performed by the Division and review of the applicant's proposal, the use of Good Combustion Controls is the BACT control technology for VOC emissions and 0.003 lb/mmBtu is the BACT VOC emissions limit. To ensure compliance with the limit, the facility will be required to perform stack test Method 25A minus Method 18 (methane removal).

Conclusion – VOC Control

The BACT selection for the auxiliary boiler is summarized below in Table 4-18:

- **Table 4-18: BACT Summary for the Auxiliary boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Good Combustion Controls	0.003 lb/MMBtu	3-hour average	Method 25A minus Method 18

Auxiliary boiler – Sulfuric Acid Mist (SAM) Emissions

Applicant's Proposal

SAM is formed by the oxidation of a portion of the SO_2 in the stack gases to SO_3, which then react with water vapor in the flue gas to form H_2SO_4.

In Application 17924, the applicant performed the 5-step BACT analysis for the SAM emissions from the auxiliary boiler. The summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant identified Fuel Selection, Wet Scrubber, Dry Scrubber and Sorbent Injection as the SAM control technologies for the auxiliary boiler. The applicant stated that the control technologies for auxiliary boiler are similar to those discussed for coal fired boiler.

Step 2: Eliminate technically infeasible options

The applicant reviewed all control technologies and identified that the low-sulfur fuel, Wet Scrubber and Dry Scrubber are the technically feasible control technologies.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant stated that use of any add on control device to auxiliary boiler is not effective as the auxiliary boiler will operate for only 876 hrs/yr. The use of ultra low sulfur fuel is the top control technology for the auxiliary boiler.

Step 4: Evaluating the Most Effective Controls and Documentation

There are no energy, environmental, or economic impacts associated with the use of ultra low sulfur diesel fuel.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for SAM emissions from the auxiliary boiler to be the use of ultra low sulfur fuel oil and a BACT SAM emissions limit of 6.0×10^{-5} lb/mmBtu. The applicant has proposed fuel certification to demonstrate compliance with the limit.

The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse in demonstration of the BACT limit (Table 4-33 of permit application).

EPD Review – SAM Control

The Division has performed independent research of the SAM BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix G. Based on the research and emission calculations performed by the Division and review of the applicant's proposal, the use of ultra low sulfur fuel is the BACT control technology for SAM emissions and 6.0×10^{-5} is the BACT SAM emissions limit. The facility will be required to perform stack test using Method 8. The Division requires the facility to use Method 8 to ensure compliance with the SAM limit, as Method 8 is the method required for SAM as per Division's Procedures for Testing and Monitoring document.

Conclusion – SAM Control

The BACT selection for the Auxiliary Boiler is summarized below in Table 4-19:

- **Table 4-19: BACT Summary for the Auxiliary boiler**

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SAM	Ultra low sulfur fuel oil	6.0×10^{-5} lb/MMBtu	3-hour average	Method 8

Diesel Fired Emergency Generator and Fire Water Pump - Background

The emergency generator (Emission Unit EG1) will be diesel fired with engine capacity of 1500 HP. The fire water pump (Emission Unit EP1) will also be diesel fired with engine capacity of 350 HP. Both of these engines will operate only during emergencies and/or maintenance cycles. The operating hours for each engine will be limited to 500 hours per year. Typical maintenance operations range from 4 to 8 hours per month.

Diesel Fired Emergency Generator and Fire Water Pump – Emissions

Applicant's Proposal

Combustion is a thermal oxidation process, which produces emissions as a byproduct of fuel combustion. Combustion of diesel fuel produces emissions of PM/PM_{10}, $PM_{2.5}$, NOx, SO_2, CO, VOC, H_2SO_4 and trace amounts of Fluorides and Lead.

In Application 17924, the applicant performed the 5-step BACT analysis for emissions from the emergency generator and fire water pump. The summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

The applicant has identified the following control technologies for emissions from the emergency engines:

Lower Emitting Process Practices

The process of controlling combustion conditions to reduce the formation of VOC, CO, NOx and PM is the generally accepted method for controlling these pollutants. Emissions of these pollutants are regulated under the NSPS promulgated in 40 CFR 60 Subpart IIII.

Add on Controls

Add on controls could potentially be used to control NO_x emissions from the operation of the diesel fired engines. The two add on controls identified included SCR and non-selective catalytic reduction (NSCR). No add on controls were identified for controlling SO_2 emissions in AP42, Section 3.3 Gasoline and Diesel Industrial Engines, Section 3.4 Large Stationary Diesel Engines, or the USEPA RBLC database.

Refined Fuels

Refined fuels include use of low sulfur diesel fuel. Traditionally, low sulfur fuels have been limited to 0.5 percent sulfur content. Recently, low sulfur diesel fuel has been developed to further reduce sulfur emission from diesel fired engines. The low sulfur fuel has also been identified as being a low ash fuel, which also reduces emissions of PM/PM_{10} and $PM_{2.5}$ in the diesel exhaust.

Step 2: Eliminate technically infeasible options

The operation of the emergency units will be limited to 500 hours per year, which translates into an operational duty cycle of 6 percent. In reviewing the feasibility of the identified control technologies, the applicant has determined that add on controls are not a feasible option for this type of operation.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has determined that Good Combustion Practices is the only feasible control technology for controlling emissions of VOC, CO and NOx. Combustion of ultra low sulfur fuel is the only feasible control technology for controlling emissions of SO_2, H_2SO_4, PM/PM_{10} and $PM_{2.5}$.

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant concluded the use of Good Combustion Practices as the top control technology for controlling emissions of VOC, CO, and NOx and the use of ultra low sulfur fuel as the top control technology for controlling emissions of SO_2, H_2SO_4, PM/PM_{10} and $PM_{2.5}$. There is no energy, environmental or economic impacts associated with the use of Good Combustion Controls or ultra low sulfur fuel.

Step 5: Selection of BACT

The applicant has proposed BACT control technology for emissions from the emergency generator and fire water pump to be the use of Good Combustion Controls and use of ultra low sulfur fuel oil. The emergency generator and the emergency fire water pump engine will comply with the emission limitations contained in 40 CFR 60 Subpart IIII. The applicant has proposed manufacturer's certification and fuel certification to demonstrate compliance with the limit.

EPD Review

The Division has performed independent research of the BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division agrees with applicant's proposal to use Good Combustion Controls and ultra low sulfur fuel, and to comply with the emission limitations contained in 40 CFR 60 Subpart IIII as a BACT. The facility shall only use diesel fuel that has a maximum sulfur content of 15 ppm (0.0015% by weight). To ensure compliance, the facility needs to install and configure the engine according to the manufacturer's specifications and keep records of fuel oil certification and hours of operation.

Conclusion

The BACT selection for the emergency generator and fire water pump is summarized below in Table 4-20:

- **Table 4-20: BACT Summary for the Emergency Generator and Fire Water Pump**

Pollutant	Control Technology	Proposed BACT Limit	Compliance Determination Method
NOx	Combustion Controls	40 CFR 60 Subpart IIII	Manufacturer's specification, fuel oil certification and records of hours of operation
CO	Combustion Controls	40 CFR 60 Subpart IIII	
VOC	Combustion Controls	40 CFR 60 Subpart IIII (for HC)	
PM/PM_{10}	Ultra low sulfur fuel oil	40 CFR 60 Subpart IIII	
$PM_{2.5}$	Ultra low sulfur fuel oil		
SO_2	Ultra low sulfur fuel oil		
H_2SO_4	Ultra low sulfur fuel oil		

Cooling Tower - Background

The cooling tower will be a multi-celled back-to-back style tower. The purpose of the cooling tower is to reduce the heat released by the condensed steam from the steam turbine. The cooling tower will be comprised of 34 cells (Emission Units S2 to S35) using drift eliminators for the reduction of drift, or the amount of water from the cooling tower carried into the ambient air in liquid form. Mineral matter present in the water droplets released in the drift is considered PM/PM_{10} emissions. A small portion of the PM emissions is estimated as $PM_{2.5}$ emissions.

Cooling Tower – PM/PM_{10} Emissions

Applicant's Proposal

In Application 17924, the applicant has performed BACT analysis for the PM/PM_{10} emissions from the cooling tower. The BACT analysis as described in Application 17924, is as follows:

Particulate emissions will be generated from the wet cooling towers in the form of drift. Drift is formed when droplets of water are entrained in the exhaust gas stream passing through the cooling tower. As the water in the droplets evaporate, the solids in the water become particulate matter. The only control method available for wet cooling towers is drift eliminators. The design of the drift eliminators dictates their control efficiency. The efficiencies range from 0.05 to 0.0005 percent (gallons of drift per gallons of cooling water).

The applicant has proposed BACT control technology for the PM/PM_{10} emissions from the cooling tower to be the use of ultra high efficiency drift eliminators and a BACT percent drift limit of 0.0005 percent from drift eliminator.

The applicant has reviewed literature and provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse in demonstration of the BACT limit. Please refer to Table 4-34 of the permit application.

EPD Review

The Division has performed independent research of the PM/PM_{10} BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division agrees with the applicant's proposal to use ultra high efficiency drift eliminators with an efficiency of 0.0005 percent to be the BACT for the wet cooling tower. The use of drift eliminators has an established record of compliance with emission regulations and has been considered BACT for similar units.

Conclusion

The BACT selection for the cooling tower is summarized below in Table 4-21:

- **Table 4-21: BACT Summary for the Cooling Tower**

Pollutant	Control Technology	Proposed BACT Limit	Compliance Determination Method
PM/PM_{10}	Drift Eliminator	Drift limit of 0.0005 percent	Manufacturer's specification

Cooling Tower – $PM_{2.5}$ Emissions

Applicant's Proposal

In Application 17924, the applicant has performed BACT analysis for the $PM_{2.5}$ emissions from the cooling tower. The BACT analysis stated in Application 17924 is as follows:

Particulate emissions will be generated from the wet cooling towers in the form of drift. Drift is formed when droplets of water are entrained in the exhaust gas stream passing through the cooling tower. As the water in the droplets evaporates, the solids in the water become particulate matter. A portion of the particulate matter generated from the cooling tower would be in the form of $PM_{2.5}$. Emissions of $PM_{2.5}$ from the cooling towers would be assumed to be filterable in nature, with no condensable $PM_{2.5}$ emissions occurring or precursor emissions.

The applicant has proposed BACT control technology for the $PM_{2.5}$ emissions from the cooling tower to be the use of ultra high efficiency drift eliminators and a BACT percent drift limit of 0.0005 percent from drift eliminator.

The applicant has reviewed literature and provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse in demonstration of the BACT limit. Please refer to Table F-12 of Exhibit F of the permit application.

EPD Review

The Division has performed independent research of the $PM_{2.5}$ BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division agrees with the applicant's proposal to use ultra high efficiency drift eliminators with an efficiency of 0.0005 percent to be the BACT for $PM_{2.5}$ emissions from the cooling tower.

Conclusion

The BACT selection for the cooling tower is summarized below in Table 4-22:

- **Table 4-22: BACT Summary for the Cooling Tower**

Pollutant	Control Technology	Proposed BACT Limit	Compliance Determination Method
$PM_{2.5}$	Drift Eliminator	Drift limit of 0.0005 percent	Manufacturer's specification

Material Handling and Storage Facilities

Particulate emissions (PM/PM_{10} and $PM_{2.5}$) will be generated from material handling systems and storage facilities. In particular, emissions will result from handling systems for coal, limestone, storage facilities for coal and limestone, solid materials handling operations (fly ash, bottom ash and gypsum) and haul roads. The particulate sources can be grouped into the following categories: transfer points, storage piles, material processing and haul roads.

Material Handling and Storage Facilities – PM/PM_{10} Emissions

Applicant's Proposal

In Application 17924, the applicant has performed BACT analysis for the PM/PM_{10} emissions from the material handling and storage facilities. The BACT analysis as described in Application 17924, is as follows:

Step 1: Identify all control technologies

The applicant has grouped the particulate sources under the material handling and storage facilities in four different categories (transfer points, storage piles, material processing and haul roads) and identified control technologies for each of these categories as follows:

1) Transfer Points
   - Enclosed transfer point with dust suppression and/or dust collector
   - Partially enclosed transfer point with dust suppression and/or dust collector
   - Dust suppression (water sprays, and use of surfactants or crusting agents)

2) Storage Piles
   - Full enclosure
   - Partial enclosure
   - Dust suppression (water sprays, surfactants, crusting agents, and seeding and covering)
   - Telescopic chutes
   - Lowering wells
   - Contouring, compaction, and stabilization
   - Minimized active cell area

3) Material Processing
   - Enclosed processing operation with dust suppression and/or dust collector

4) Haul Roads
   - Paving
   - Dust suppression (water sprays and surfactants)

Step 2: Eliminate technically infeasible options

In this section, the applicant has discussed technical feasibilities of the above mentioned control technologies and eliminated technically infeasible control technologies.

1) Transfer Points

Transfer points include coal railcar unloading (Emission Unit A4), transfer point for PRB coal (Emission Units A6 and A8), transfer point for Illinois #6 coal (Emission Units A7 and A9), limestone railcar unloading (Emission Unit A5), limestone transfer point (Emission Unit A10), fly ash mechanical exhausters (Emission Unit S43), bottom ash transfer point to storage bin and bottom ash transfer point from bin to truck (Emission Unit A3). In addition, the tripper deck (Emission Unit S41), fly ash silo (Emission Unit S37), Hg sorbent silo (Emission Unit S38), SO_3 sorbent silo (Emission Unit S36), pre-treatment soda ash silo (Emission Unit S44), and pre-treatment hydrated lime silo (Emission Unit S39) also include transfer points.

Three control options were identified in Step 1 as potential control for transfer points. The total enclosure with dust suppression is not a technically feasible option for coal railcar unloading, limestone railcar unloading, transfer point for PRB coal, and transfer point for Illinois #6 coal because of railcar handling procedures and safety procedures. The other two options, partial enclosures with dust suppression and/or dust collectors, and dust suppression (use of water sprays, surfactants, or crusting agents), are considered technically feasible for the remainder of the transfer points.

2) Storage Piles

Storage piles include an active pile for PRB coal (Emission Unit A8), an active pile for Illinois #6 coal (Emission Unit A9), an inactive pile for PRB coal (Emission Unit A6), an inactive pile for Illinois #6 coal (Emission Unit A7), an active pile for limestone (Emission Unit A10), a gypsum pile and the solid materials handling operations (Emission Units A1 and A2). Seven potential options were identified in Step 1 for control of emissions from storage piles. Of the seven options identified, the full enclosure control strategy for the storage piles is not technically feasible.

3) Material Processing

Material processing areas on-site include coal and limestone preparation facilities (Emission Units S40 and S42). Both processing operations are to be enclosed inside a separate building. The control option identified in Step 1, enclosing processing operations and using dust suppression and/or a dust collector, is technically feasible.

4) Haul Roads

Haul roads (Emission Units P1 to P21 and U1 to U15) on-site are primarily internal roadways used by the facility to transport combustion byproducts to the on-site storage facility. Particulate emissions are generated primarily from re-entrained road dust. The two control strategy options identified in Step 1 are technically feasible to control roadway dust.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

In this section, the applicant has discussed ranking for the technically feasible control technologies.

1) Transfer Points

Except the rail unloading operations and transfer to storage pile, the options for controlling particulate emissions from the transfer points, the three options are ranked in order of effectiveness as: (1) enclosed transfer point with dust suppression and/or dust collector, (2) partially enclosed transfer point with dust suppression and/or dust collector, and (3) dust suppression (water sprays or use of surfactants or crusting agents).

2) Storage Piles

The ranking of the control strategies for storage piles is similar to the ranking for transfer points. The full or partial enclosure is the most effective control strategy to minimize emissions, but is technically infeasible due to the size of the piles and potential hazardous environments that could be found inside such a structure. Dust suppression techniques such as water sprays with or without chemical additives such as surfactants and crusting agents will be the most effective control for the storage piles. Use of telescoping spouts and lowering wells will minimize the creation of particulates for materials being added to or removed from the piles. Dust suppression sprays are also effective during pile maintenance operations.

Particulate emissions from operations at the on-site storage facility (solid materials handling facility) will be most effectively controlled by a combination of physical control strategies, including contouring, compaction, stabilization, and cover, in conjunction with management practices, including minimizing the active work areas in the on-site storage facility. The operations and maintenance practice will be fully identified in the solid materials handling operations plan.

3) Material Processing

Since only one option was identified for on-site material processing, no ranking is required.

4) Haul Roads

The two options identified as control options for haul roads were paving and dust suppression through the use of water sprays and/or chemical additives. The applicant is planning to implement both control strategies.

Step 4: Evaluating the Most Effective Controls and Documentation

1) Transfer Points

Fully enclosed transfer point with dust suppression and/or dust collector provides the most effective controls for particulate emissions. Demonstrated BACT testing indicates that control efficiencies of 80 to 99 percent are achievable. The applicant is planning to use fully enclosed transfer points with dust controls where feasible.

2) Storage Piles

Use of dust suppression sprays with or without chemical additives is the most effective control strategy after full and partial enclosure was identified as being technically infeasible. The applicant will be using water sprays, surfactants, seeding agents, and contouring to obtain a control efficiency of 90 percent. Telescoping chutes and lowering well will also be used in the transfer point to further minimize emissions from storage pile operation. Covering, limiting the active cell area, and other best management practices (BMPs) will be used in the on-site storage facility to reduce particulate emissions.

3) Material Processing

The facility will use an enclosed building with fabric filter to control emissions for the coal and limestone processing area.

4) Haul Roads

Dust suppression techniques, including the use of water sprays, in conjunction with paving haul roads, will obtain a control efficiency of 90 percent. Regular cleaning and application of water sprays will also reduce roadway dust emissions.

Step 5: Selection of BACT

The applicant has proposed to use a combination of enclosures, dust collectors, telescopic chutes, lowering wells, wet suppression systems, covering, and crusting agents as discussed in the above steps for different categories under material handling as BACT. Baghouses with flow rates greater than 1,000 acfm will have a maximum average outlet loading of 0.005 grain per dry standard cubic feet (gr/dscf). Emissions from transfer points will be reduced by 90 percent using enclosures in conjunction with dust suppression.

Storage pile particulate emissions will be reduced 90 percent through the use of water sprays in conjunction with BMPs. Fugitive emissions from the coal storage piles will be reduced through the use of a retractable chute in conjunction with water sprays, surfactants, crusting agents, contouring, and covering. Fugitive emissions from the limestone pile will be reduced by 90 percent through the use of a lowering well when removing material from the pile.

Haul road emissions will be reduced by 90 percent by paving the haul road in conjunction with water sprays and surfactants. The applicant has provided data for the permitted facilities from USEPA RACT/BACT/LAER Clearinghouse in demonstration of the emission limit of 0.005 gr/dscf and proposed control procedures. Please refer to Table 4-35 of the permit application.

EPD Review

The Division has performed independent research of the PM/PM_{10} BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division agrees with the applicant's proposal to use combination of enclosures, dust collectors, telescopic chutes, lowering wells, dust suppression systems, contouring and covering be the BACT for the material handling and storage facilities.

Conclusion

The BACT selection for the material handling and storage facilities is summarized below in Table 4-23:

- **Table 4-23: BACT Summary for the Material Handling and Storage Facilities**

Pollutant	Source ID	Emission Unit	Control Technology	Compliance Determination Method
PM/PM_{10}	A4	Coal Rail Unloading	Dust Suppressant and/or Water Sprays and Partial Enclosure	
PM/PM_{10}	S46	PRB Conveyor Stackout	Insertable Filter (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	S47	Illinois # 6 Conveyor Stackout	Insertable Filter (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	S40	Coal Crusher House	Baghouse (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	S41	Tripper Decker	Baghouse (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	A8	Active PRB Coal Pile and Transfer Point	Dust Suppressant and/or Water Sprays, telescopic chute and lowering wells	
PM/PM_{10}	A9	Active Illinois # 6 Coal Pile and Transfer Point	Dust Suppressant and/or Water Sprays, telescopic chute and lowering wells	
PM/PM_{10}	A6	Inactive PRB Coal Pile	Dust Suppressant and/or Water Sprays, telescopic chute and lowering wells	
PM/PM_{10}	A7	Inactive Illinois # 6 Coal Pile	Dust Suppressant and/or Water Sprays, telescopic chute and lowering wells	

Pollutant	Source ID	Emission Unit	Control Technology	Compliance Determination Method
PM/PM_{10}	S43	Fly Ash Mechanical Exhausters	Baghouse (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	S37	Fly Ash Silo	Bin Vent Filter (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	A3	Bottom Ash Transfer to Bin And from Bin to Truck	Water Sprays	
PM/PM_{10}	A1	Solid Material Handling-ash	Dust Suppressant and/or Water Sprays, contouring and covering	
PM/PM_{10}	A2	Solid Material Handling-Gypsum	Dust Suppressant and/or Water Sprays, contouring and covering	
PM/PM_{10}	A5	Limestone Railcar Unloading Station	Dust Suppressant and/or Water Sprays and Partial Enclosure	
PM/PM_{10}	S48	Limestone Stackout	Insertable Filter (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	S42	Limestone Preparation Building	Baghouse (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	A10	Limestone Pile and Transfer Point	Dust Suppressant and/or Water Sprays, telescopic chute and lowering wells	
PM/PM_{10}	S36	SO_3 Sorbent Silo	Bin Vent Filter (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	S38	Mercury Sorbent Silo	Bin Vent Filter (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	S44	Pretreatment Soda Ash Silo	Bin Vent Filter (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	S39	Pretreatment Hydrated Lime Silo	Bin Vent Filter (0.005 gr/dscf)	Manufacturer's Specification
PM/PM_{10}	P1-P21	Paved Roadway Travel	Water sprays and/or Dust suppressant	
PM/PM_{10}	U1-U15	Unpaved Roadway Travel	Water sprays and/or Dust suppressant	

Material Handling and Storage Facilities – $PM_{2.5}$ Emissions

Applicant's Proposal

In Application 17924, the applicant has performed BACT analysis for the $PM_{2.5}$ emissions from the material handling and storage facilities. The BACT analysis as stated in Application 17924 is as follows:

Emissions of $PM_{2.5}$ from material handling and storage facilities would be in a Filterable $PM_{2.5}$ only, with no expected emissions of Condensable $PM_{2.5}$ or precursor emissions.

In this section, the applicant addressed point sources of emissions from the material handling and storage facilities. The applicant stated that control strategies identified for control of fugitive emissions in section 4.7 of the application would also be effective in the control of $PM_{2.5}$ emissions. The applicant was not able to find any information that is more effective in control of fugitive $PM_{2.5}$ emissions (e.g. use of different crusting agents, watering techniques etc.).

For $PM_{2.5}$ emissions from point sources, the applicant proposed Insertable Filter/Baghouse/Bin Vent Filter as BACT control technology. These technologies are determined as BACT for PM/PM_{10} emissions from point sources. In conducting the BACT analysis for the coal fired boiler, the applicant found that some fabrics are more effective than others in removing $PM_{2.5}$.

EPD Review

The Division has performed independent research of the $PM_{2.5}$ BACT analysis and used the following information:

- Final/Draft permits for similar sources
- USEPA RACT/BACT/LAER Clearinghouse

The Division agrees with the applicant's proposal to use Insertable Filter/Baghouse/Bin Vent Filter as appropriate. The Division does not recommend any membrane technology for Fabric Filter bags at this time, as there is not enough research or data available.

Conclusion

The BACT selection for the material handling and storage facilities is summarized in Table 4-23.

5.0 TESTING AND MONITORING REQUIREMENTS

Coal Fired Boiler S1

The Coal Fired Boiler S1 is subject to BACT requirements for NOx, VOC, Total PM/PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4 emissions, BACT and MACT requirements for CO, Filterable PM/PM_{10}, HF emissions, MACT requirements for HCl and have BACT avoidance limit for Lead. The Filterable PM BACT and MACT requirements subsume the PM requirements specified in Georgia Rule 391-3-1-.02(2)(d) and NSPS Subpart Da; the NOx BACT requirement subsumes the NOx requirements specified in Georgia Rule 391-3-1-.02(2)(d) and NSPS Subpart Da; the SO_2 BACT requirement subsumes the SO_2 requirement specified in Georgia Rule 391-3-1-.02(2)(g) and NSPS Subpart Da.

In addition, the general provisions of NSPS provides avenues to obtain permission to use alternative testing and monitoring protocols, and in some cases, to waive testing requirements, when justified.

Please refer to Appendix A for testing and monitoring requirements for Coal Fired Boiler S1 under MACT.

EPD proposes the following testing requirements for the Coal Fired Boiler S1:

a. NOx CEMS to verify compliance with the NOx BACT emission standard.
b. SO_2 CEMS to verify compliance with the SO_2 BACT emission standard.
c. CO CEMS to verify compliance with the CO BACT and MACT emission standard.
d. PM CEMS to verify compliance with the PM Filterable BACT and MACT emission standard.
e. Continuous Opacity Monitor to verify compliance with the opacity.
f. Mercury CEMS to verify compliance with the Mercury BACT and MACT emission standard.
g. Initial performance test (Method 25A minus Method 18) for VOC at base load and 50 percent load to verify compliance with VOC BACT emission standard.
h. Initial performance tests (Method 5 or 17 in conjunction with Method 202) while firing sub-bituminous coal and a 50/50 blend of sub-bituminous and bituminous coal for Total PM/PM_{10} at base load to verify compliance with PM/PM_{10} BACT emission standard.
i. Initial performance tests (Method 5 or 17 or any other test method approved by the Director in conjunction with Method 202) while firing sub-bituminous coal and a 50/50 blend of sub-bituminous and bituminous coal for Total $PM_{2.5}$ at base load to verify compliance with $PM_{2.5}$ BACT emission standard.
j. Initial performance test (Method 26A) while firing sub-bituminous coal and a 50/50 blend of sub-bituminous and bituminous coal for HF at base load to verify compliance with Fluoride BACT and MACT emission standard.
k. Initial performance test (Method 8) while firing sub-bituminous coal and a 50/50 blend of sub-bituminous and bituminous coal for H_2SO_4 at base load to verify compliance with H_2SO_4 BACT emission standard.
l. Initial performance test (Method 26A) while firing sub-bituminous coal and a 50/50 blend of sub-bituminous and bituminous coal for HCL at base load to verify compliance with HCl MACT emission standard.
m. Initial performance test (Method 29) while firing sub-bituminous coal and a 50/50 blend of sub-bituminous and bituminous coal for lead at base load to verify compliance with lead BACT avoidance limit.
n. Performance test for HF and HCl on the Wet Limestone Scrubber to establish the minimum value for the scrubbant pH.
o. Performance test for H_2SO_4 to establish the minimum value for the sorbent injection rate.

EPD proposes the following monitoring requirements for the Coal Fired Boiler S1:

a. NOx CEMS to verify compliance with the NOx BACT emission standard.
b. SO_2 CEMS to verify compliance with the SO_2 BACT emission standard.
c. PM CEMS to verify compliance with the PM Filterable BACT emission standard.
d. CO CEMS to verify compliance with the CO BACT emission standard.
e. Continuous Opacity Monitor to verify compliance with the opacity.
f. CO_2 or O_2 monitors at each location where emissions are monitored to measure the CO_2 or O_2 content of the flue gas to correct pollutant emission concentration.
g. Mercury CEMS to verify compliance with the Mercury BACT emission standard.
h. Instrumentation to measure the heating value and mass of fuel combusted to calculate the total heat input to the boiler.
i. Instrumentation to measure the gross electrical output of the boiler.
j. Instrumentation to measure scrubbant pH on the Wet Limestone Scrubber.
k. Instrumentation to measure H_2SO_4 sorbent injection rate.
l. Fuel oil analysis for sulfur content.

Auxiliary Boiler S45

The Auxiliary Boiler S45 is subject to BACT requirements for NOx, CO, VOC, PM/PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4 emissions. The boiler is subject to the opacity requirement under NSPS Subpart Db.

Please refer to Appendix A for testing and monitoring requirements for Auxiliary Boiler S45 under MACT.

EPD proposes the following testing requirements for the Auxiliary Boiler S45:

a. Initial performance test (Method 7 or 7E) for NOx to verify compliance with NOx BACT emission standard.
b. Initial performance test (Method 10) for CO to verify compliance with CO BACT emission standard.
c. Initial performance test (Method 5 or 17 or Method 5 or 17 in conjunction with Method 202) to verify compliance with PM/PM_{10}, Total PM/PM_{10} and Total $PM_{2.5}$ BACT emission standards.
d. Fuel sampling to verify compliance with SO_2 BACT emission standard.
e. Initial performance test (Method 25A minus Method 18) for VOC to verify compliance with VOC BACT emission standard.
f. Initial performance test (Method 8) for H_2SO_4 to verify compliance with H_2SO_4 BACT emission standard.
g. Initial performance test (Method 9) for opacity to verify compliance with opacity standard.

EPD proposes the following monitoring requirements for the Auxiliary Boiler S45:

a. Instrumentation to measure the operating hours of the boiler.
b. Fuel oil analysis for sulfur content.

Coal Handling Particulate Sources

Coal Handling Particulate Sources (Emission Units A4, A6 to A9, S40, S41, S46 and S47) and coal conveying systems are subject to NSPS Subpart Y and requires performance testing for opacity in accordance with 40 CFR 60.254.

Limestone Management Particulate Sources

Limestone Management Particulate Sources are subject to NSPS Subpart OOO. Limestone Stackout S48 and the vents of Limestone Preparation Building S42 require performance testing for PM as per 40 CFR 60.675. Limestone Railcar Unloading Station A5 and the openings (except for vents) of Limestone Preparation Building S42 require performance testing for opacity as per 40 CFR 60.675. NSPS Subpart OOO requires to perform monitoring on Limestone Stackout S48 and the vents of Limestone Preparation Building S42, according to the methods and procedures contained in 40 CFR 60.674(c), (d) or (e) and requires periodic inspection of dust suppression system to control fugitive emissions according to the methods and procedures contained in 40 CFR 60.674(b).

Other Particulate Sources

PRB Conveyor Stackout S46, Illinois # 6 Conveyor Stackout S47, Coal Crusher House S40, Tripper Decker S41, Fly Ash Mechanical Exhausters S43, Fly Ash Silo S37, SO_3 Sorbent Silo S36, Mercury Sorbent Silo S38, Pretreatment Soda Ash Silo S44, Pretreatment Hydrated Lime Silo S39 are subject to BACT requirements for PM. EPD proposes initial performance testing for PM to verify compliance with PM standard.

Emergency Generator and Fire Water Pump

Emergency Generator EG1 and Fire Water Pump EP1 are subject to NSPS Subpart IIII. EPD proposes to track the hours operated during emergency service and in non-emergency service (maintenance and/or testing), to record the reason the engine was in operation during those time, and to record the cumulative total hours of operation. Fuel sampling is required to verify compliance. The facility needs to purchase certified engines to demonstrate compliance with the NSPS Subpart IIII emission limits for the Emergency Diesel Generator EG1 and need to comply with 40 CFR 60.4211(b) to demonstrate compliance with the NSPS Subpart IIII emission limits for the Emergency Fire Water Pump EP1.

6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed new major stationary source. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed new major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for NO_2, CO, $PM_{2.5}$, PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, and PM_{10}.

The proposed project at Plant Washington triggers PSD review for NOx, SO_2, CO, PM, PM_{10}, VOC, H_2SO_4 and Fluorides. Georgia is currently using PM_{10} as a surrogate for $PM_{2.5}$ as allowed for SIP-approved states under EPA's $PM_{2.5}$ Transition Policy. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for NO_2, CO, PM_{10}, and SO_2. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages. Although not currently required under the EPA $PM_{2.5}$ Transition policy, the application includes dispersion modeling for direct PM $_{2.5}$.

Modeling Requirements

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*.

The proposed project will cause net emission increases of NOx, SO_2, CO, PM, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4 and Fluorides that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. VOC does not have an established PSD modeling significance levels (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm). Since the project's VOC or NOx emissions are projected to exceed 100 tons-per-year (tpy), the facility is required to conduct an ozone impacts analysis.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the NO_2, CO, PM_{10}, and SO_2 emissions increases at the Plant Washington would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established monitoring significant level (MSL). The MSL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the MSL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for NO_2, SO_2, CO, PM_{10} and Fluorides.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the MSL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. $PM_{2.5}$ does not yet have established MSLs (3 options proposed on 9/12/07)

- **Table 6-1: Summary of Modeling Significance Levels**

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m^3)	PSD Monitoring Deminimis Concentration (ug/m^3)
PM_{10}	Annual	1	--
	24-Hour	5	10
SO_2	Annual	1	--
	24-Hour	5	13
	3-Hour	25	--
NO_2	Annual	1	14
CO	8-Hour	500	575
	1-Hour	2000	--
Fl	24-Hour	--	0.25

<u>NAAQS Analysis</u>

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS are listed in Table 6-2 below.

- **Table 6-2: Summary of National Ambient Air Quality Standards**

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
PM_{10}	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
$PM_{2.5}$*	Annual	15 / 15	--
	24-Hour	35 / 35	--
SO_2	Annual	80 / None	0.03 / None
	24-Hour	365 / None	0.14 / None
	3-Hour	None/1300	None / 0.5
NO_2	Annual	100 / 100	0.053 / 0.053
CO	8-Hour	10,000 / None	9 / None
	1-Hour	40,000 / None	35 / None

*PM_{10} modeling is current surrogate for $PM_{2.5}$.

If the maximum pollutant impact calculated in the Significance Analysis exceeds the MSL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at the Plant Washington, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

PSD Increment Analysis

The PSD Increments were established to "prevent deterioration" of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a "reduced" ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions "consume" more that the available PSD Increment).

U.S. EPA has established PSD Increments for NO_2, SO_2, and PM_{10}; no increments have been established for CO or $PM_{2.5}$ (however, $PM_{2.5}$ increments are expected to be added soon). The PSD Increments are further broken into Class I, II, and III Increments. The Plant Washington is located in a Class II area. The PSD Increments are listed in Table 6-3.

- **Table 6-3: Summary of PSD Increments**

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
PM_{10}	Annual	4	17
	24-Hour	8	30
SO_2	Annual	2	20
	24-Hour	5	91
	3-Hour	25	512
NO_2	Annual	2.5	25

To demonstrate compliance with the PSD Increments, the increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the facility and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class II increment for any pollutant greater than the MSL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NO_2 is February 8, 1988, and the major source baseline for SO_2 and PM_{10} is January 6, 1975. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for SO_2 as October 23, 2000.

Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix D of this Preliminary Determination and in Section 5.0 of the permit application.

Modeling Results

Table 6-4 show that the proposed project will not cause ambient impacts of NOx, CO and PM_{10} above the appropriate MSLs. Because the emissions increases from the proposed project result in ambient impacts less than the MSLs, no further PSD analyses were conducted for these pollutants.

However, ambient impacts above the MSLs were predicted for SO_2 for the 3-hour and 24-hour averaging periods, requiring NAAQS and Increment analyses be performed for SO_2.

- **Table 6-4: Class II Significance Analysis Results – Comparison to MSLs**

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	MSL (ug/m^3)	Significant?
NO_2	Annual	1989	338762	3659340	0.4578	1	No
PM_{10}	24-hour	1989	337260	3660883	4.951	5	No
	Annual	1989	336977	36607484	0.4613	1	No
SO_2	3-hour	1991	336637	3659011	30.38	25	**Yes**
	24-hour	1987	338468	3658817	11.31	5	**Yes**
	Annual	1989	338763	3659340	0.601	1	No
CO	1-hour	1987	338037	3661311	127.63	2000	No
	8-hour	1988	336037	3659511	60.01	500	No

Data for worst year provided only.

As indicated in the tables above, maximum modeled impacts were below the corresponding MSLs for NO_2, CO and PM_{10}. However, maximum modeled impacts were above the MSLs for SO_2 for the 3-hour and 24-hour averaging periods. Therefore, a Full Impact Analysis was conducted for SO_2.

Significant Impact Area

For any off-site pollutant impact calculated in the Significance Analysis that exceeds the MSL, a Significant Impact Area (SIA) must be determined. The SIA encompasses a circle centered on the facility being modeled with a radius extending out to the lesser of either: 1) the farthest location where the emissions increase of a pollutant from the proposed project causes a significant ambient impact, or 2) a distance of 50 kilometers. All sources of the pollutants in question within the SIA plus an additional 50 kilometers are assumed to potentially contribute to ground-level concentrations and must be evaluated for possible inclusion in the NAAQS and Increment Analysis.

Based on the results of the Significance Analysis, the distance between the facility and the furthest receptor from the facility that showed a modeled concentration exceeding the corresponding MSL was determined to be less than 5.42 (24-hr averaging period) and 1.95 (3-hr averaging period) kilometers, respectively for SO_2. To be conservative, regional source inventories for SO_2 were prepared for sources located within 56 kilometers of the plant.

NAAQS and Increment Modeling

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the facility's SIA are ideally included in this regional inventory. Plant Washington requested and received an inventory of NAAQS and PSD Increment sources from Georgia EPD. Plant Washington reviewed the data received and calculated the distance from the plant to each facility in the inventory. All sources more than 50 km outside the SIA were excluded.

The distance from the facility of each source listed in the regional inventories was calculated, and all sources located more than 50 kilometers from the plant were excluded from the analysis. Additionally, pursuant to the "20D Rule," facilities outside the SIA were also excluded from the inventory if the entire facility's emissions (expressed in tons per year) were less than 20 times the distance (expressed in kilometers) from the facility to the edge of the SIA. In applying the 20D Rule, facilities in close proximity to each other (within approximately 2 kilometers of each other) were considered as one source. Then, any Increment consumers from the provided inventory were added to the permit application forms or other readily available permitting information.

The regional source inventory used in the analysis is included in the permit application and in the modeling files on compact disk.

NAAQS Analysis

In the NAAQS analysis, impacts within the facility's SIA due to the potential emissions from all sources at the facility and those sources included in the regional inventory were calculated. Since the modeled ambient air concentrations only reflect impacts from industrial sources, a "background" concentration was added to the modeled concentrations prior to assessing compliance with the NAAQS.

The results of the NAAQS analysis for SO_2 are shown in Table 6-5. For the short-term averaging periods, the impacts are the highest second-high impacts. For the annual averaging period, the impacts are the highest impact. When the total impact at all significant receptors within the SIA are below the corresponding NAAQS, compliance is demonstrated. The short-term impacts include the project start-up scenario emissions. As shown, the maximum predicted SO_2 concentrations, including background concentrations, were predicted to comply with the NAAQS for SO_2.

Table 6-5: NAAQS Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Background (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
SO_2	3-hour*	1989	331600	3661700	118.3	187	305.3	1300	No
	24-hour*	1989	334400	3664500	42.49	41	83.49	365	No
	Annual	1989	338864	3659512	7.25	8	15.25	80	No

Data for worst year provided only.
* Reported concentrations include start-up emissions.

Increment Analysis

The minor source PSD baseline date for SO_2 in Washington County is October 23, 2000. Emissions of Washington County sources that began operation prior to that date were not included in the offsite PSD Increment inventory. The modeled regional PSD Class II increment consumption results for SO_2 are presented in Table 6-6 for all increment-consuming sources. The short-term SO_2 impacts include the project start-up scenario emissions.

Table 6-6: Increment Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
SO_2	3-hour*	1990	336599	3660652	58 (28.4)	512	No
	24-hour*	1988	336537	3659211	18.1 (10.3)	91	No
	Annual	1987	338517	3658904	1.92	20	No

Data for worst year provided only
*Reported concentrations include start-up emissions (Concentrations at worst –case load, 100% are in parentheses for perspective).

Table 6-6 demonstrates that the impacts are below the corresponding increments for SO_2.

Ambient Monitoring Requirements

- **Table 6-7: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels**

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
NO_2	Annual	1989	338762	3659340	14	0.4578	No
PM_{10}	24-hour	1989	337260	3660883	10	4.951	No
SO_2	24-hour	1987	338468	3658817	13	11.31	No
CO	8-hour	1988	336037	3659511	575	60.01	No
Fl	24-hour	1987	338468	3658817	0.25	0.02	No

Data for worst year provided only

The impacts for NO_2, CO, SO_2, PM_{10} and Fl quantified in Table 6-4 of the Class II Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 6-1, to determine if ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding de minimis concentrations, no pre-construction monitoring is required for NO_2, PM_{10}, SO_2, CO and Fl.

As noted previously, the VOC *de minimis* concentration is mass-based (100 tpy) rather than ambient concentration-based (ppm or μg/m^3). Projected VOC emissions increases resulting from the proposed modification exceed 100 tpy. Since the project's VOC or NOx emissions are projected to exceed 100 tons-per-year (tpy), the facility was required to conduct an ozone impacts analysis.

Ozone Impact Analysis

An analysis of Plant Washington's potential ozone impacts is performed in Section 5.0 of the application. The last three years of the 4th highest monitored 8-hour averaged ozone concentrations at each of the three ozone monitoring stations closest to the Plant Washington site are summarized in Table 5-1A of the application. This table indicates that the latest three-year rolling average ozone design concentration is less than the 8-hour ozone standard at only the Columbia County monitor. Plant Washington elaborates that Columbia County is closer to Washington County in population, vehicle miles traveled, and NOx emissions density than the other two counties (Bibb and Richmond). Plant Washington extrapolates that Washington County is lower in each of these parameters, all of which contribute to ozone formation, than Columbia County.

Preconstruction monitoring for ozone can be waived in the event that representative ozone ambient air quality monitoring data for the area is available. Plant Washington has indicated that Washington County is conservatively represented by the monitored data collected by GA EPD in Columbia County. For this reason, it is recommended that preconstruction monitoring for ozone be waived for the Plant Washington project. The Plant Washington Generating Station is not anticipated to cause, or substantially contribute to, an excess of the 8-hour ozone standard in the region.

CAMx Photochemical Modeling Review

Photochemical modeling was conducted by GA EPD for Plant Washington. The purpose of the modeling was to assess the impacts of Plant Washington emissions on Ozone and $PM_{2.5}$ concentrations on nearby monitoring stations. The simulations were conducted with the Comprehensive Air quality Model with extensions (CAMx). CAMx is a 3-D Eulerian (grid-based) photochemical transport model (includes gas-phase chemistry, aqueous phase chemistry, and equilibrium processes) that can simulate the hour-by-hour production of secondary air pollutants such as ozone and condensable particles in addition to primary particles. EPD's CAMx Photochemical Modeling Review in Appendix E of this Preliminary Determination discusses the procedures used to perform this modeling. The air contaminants that were modeled included NO, NO_2, SO_2, CO, NH_3, VOC, speciated direct $PM_{2.5}$, and sulfuric acid mist.

The results of this modeling evaluation are summarized in the Tables 1 to Table 3 of the review document and indicate that air emissions associated with the proposed project will have minimal impacts on Ozone and $PM_{2.5}$ concentrations at nearby monitors. All modeling input and output files generated in this analysis are available at GA EPD.

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations.

Seven PSD Class I areas exist within 300 km of the proposed facility. These areas and corresponding Federal Land Manager's (FLM) and the distance from Plant Washington are as follows:

Class I Area	FLM	Distance (km)
Great Smoky Mountains National Park, NC/TN	NPS	273
Cohutta Wilderness Area (WA), GA/TN	U.S.F.S.	261
Shining Rock WA, NC	U.S.F.S.	252
Joyce Kilmer/Slickrock WA, NC	U.S.F.S.	276
Cape Romain WMA, SC	U.S. F&WS	289
Wolf Island WMA, GA	U.S. F&WS	231
Okefenokee WMA, GA	U.S. F&WS	227

Project application materials, including modeling input and output files have been made available to each of these FLM agencies. These files include receptor locations for each Class I area, expressed in Lambert Conformal Coordinates (LCC) with receptor elevations in meters AMSL, as downloaded from the NPS receptor database. The facility contacted the "FLM permit coordinator" (presumably with the U.S. F&WS, since that agency manages the two Class I areas closest to Plant Washington) for guidance as to the assessments required of the project by that FLM agency. They were asked to perform visibility and acid deposition Air Quality Related Value (AQRV) assessments of the project, in accordance with the recommendations of the Federal Land Manager Air Quality Workgroup (FLAG) Phase I report (12/2000).

Class I Area Significance Analysis

The maximum predicted NO_2, SO_2 and PM_{10} (used as a surrogate for $PM_{2.5}$ assessments) concentrations at all Class I areas were below the proposed Class I area Increment significant impact levels (SILs) as shown in Section 7 of the permit application. The CALPUFF modeling system (CALPUFF, version 5.8, level 070623, POSTUTIL 1.56, level 070627, CALPOST 5.6394, level 070622) was used to assess all Class I area impacts. The facility has requested a 24-hour average emission limit of 0.08 lb/mmBtu for SO_2 in order to avoid conducting a cumulative Increment assessment at Wolf Island. This limit will be added to the permit. The maximum predicted Increment concentrations are shown in Table 6-9.

- **Table 6-9: Class I Significance Analysis Results – Comparison to SILs**

Pollutant	Averaging Period	Model Met Data Period/Area	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	SIL (ug/m^3)	Significant ?
NO_2	Annual	2002/Wolf Island WMA	472657	3469628	0.002	0.1	No
PM_{10}	24-hour	03122524/Wolf Island WMA	468694	3469639	0.057	0.3	No
	Annual	2002/Cape Romain WMA	625889	3639472	0.0025	0.2	No
SO_2	3-hour	02021424/Cohutt a WA	171939	3861622	0.71	1.0	No
	24-hour	03122524/Wolf Island WMA	468694	3469639	0.1996	0.2	No
	Annual	2002/Wolf Island WMA	472657	3469628	0.008	0.1	No

No Class I SILs are predicted to be exceeded. For this reason, no further analysis of Class I Increment impacts was conducted.

Class I Area Air Quality Related Value (AQRV) Analysis

The facility conducted regional haze visibility and acid deposition analyses, using the maximum project emission rates, at all seven Class I areas located within 300 km of the project. The CALPUFF model system was used in these analyses.

Deposition: The maximum nitrogen deposition rate predicted for any of the seven Class I areas was predicted to be 0.0045 kg/ha/yr at the Shining Rock WA (in 2003). This maximum-modeled nitrogen deposition rate is below the Federal Land Manager (FLM) Deposition Analysis Threshold (DAT) level of 0.01 kg/ha/yr. As a result, the nitrogen deposition impacts at each of the seven Class I areas are considered acceptable.

The maximum sulfur deposition rate at any of the seven Class I areas was predicted occur at the Cohutta WA, and to be 0.0135 kg/ha/yr (in 2002). This maximum-modeled sulfur deposition rate is above the DAT level of 0.01 kg/ha/yr. At Cohutta, the DAT was also exceeded in 2003 (0.0117 kg/ha/yr). The sulfur DAT was predicted to be slightly exceeded at Cape Romain (2001 and 2002), the Great Smoky Mountain National Park (2003), the Joyce Kilmer/Slickrock WA (2003), and the Shining Rock WA (2003). These exceedances were less than or equal to the maximum sulfur deposition rate predicted at Cohutta during 2003. The averages of the three annual-modeled maximum rates of sulfur deposition at each Class I area are below the DAT level (except for Cohutta, 0.0112 kg/ha/yr; and Cape Romaine, 0.0101 kg/ha/yr). The maximum annual nitrogen and sulfur deposition rates predicted as a result of the project at each Class I area are presented on Table 7-8 of the application. An exceedance of the DAT thresholds may be deemed acceptable by the FLM, depending on the number of exceedances predicted to occur at individual Class I areas, and other factors. An exceedance of the DAT thresholds is not equivalent to a finding of adverse impact, but indicates additional analysis may be requested.

The U.S.F.S. FLM reviewed the Shining Rock WA Class I area modeling conducted for Plant Washington, on the basis that Shining Rock is the closest U.S.F.S.-managed area to Plant Washington. That review concluded the impacts of Plant Washington on Forest Service-managed Class I areas are acceptable and do not warrant further analysis.

During this review, it was observed that project short-term SO_2 emission rates were used in assessing sulfur deposition. The use of the appropriate annual emission limits, which are less than 50% of the short-term limits, would inhibit the calculation of any excesses of the sulfur DAT.

Visibility: Visibility impacts due to regional haze are an AQRV of each of the seven Class I areas within 300 km of Plant Washington. The assessment of visibility impacts from the proposed facility was computed by determining the change in light extinction coefficient at each Class I area due to primary particulate matter emissions from the facility and secondary particulate products of atmospheric reactions during plume transport, such as sulfates and nitrates. The visibility impacts were calculated using CALPOST Method 2, at 95% relative humidity. The visibility impacts were computed as a percentage change in the 24-hour averaged light extinction coefficient (βext) above natural background light extinction. The 8th highest visibility impacts are indicated for each Class I area on Table 7-7. The largest 8th highest visibility impact of the project was predicted to occur at the Cape Romain WMA in 2002 (2.93%). The facility also presented a refined estimate of the visibility impacts at each Class I area using CALPOST Method 6 (see Table 7-6). The 8th highest maximum Method 6 visibility impact was 1.44% at Cape Romain in 2002. The regional haze acceptable impact level for screening (project-only) modeling is a 5% change in the βext. No Plant Washington project impacts were predicted to exceed this level of change.

7.0 ADDITIONAL IMPACT ANALYSES

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

Soils and Vegetation

The U.S. EPA has developed certain screening concentrations below which it can be reasonably assumed that the soils and vegetation in the vicinity of a proposed project will not experience any adverse effects due to air emissions associated with the project. These threshold concentrations are listed in Table IV-1 of the Model Request Form that is attached to the EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix D, and were compiled from EPA's Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA, 1980). Table IV-1 presents a comparison of the proposed facility's worst-case impacts to these screening concentrations. Review of that table indicates the highest predicted impacts are all well below the screening concentrations. In addition, the facility has been modeled to demonstrate compliance with all applicable NAAQS, which are, in part, based on acceptable levels of environmental impact.

Growth

The growth analysis is a projection of the commercial, industrial, residential and other growth that may be projected to occur in the area as a result of the construction and operation of the proposed source. The anticipated increase in industrial, commercial, or residential growth in the area as a direct result of the proposed project will be negligible. Construction of the new power generation unit will require a temporary construction work force that will fluctuate from approximately 100 to an estimated 500 people for approximately 24 months. Many construction workers will be hired locally. Operation of the facility is expected to create between 100-150 permanent jobs. No significant amount of related industrial growth is expected to accompany the operation of the plant. Since no significant associated commercial or industrial growth is projected as a result of the proposed action, negligible growth-related air pollution impacts are expected.

Class II Area Visibility Analysis

An analysis of the conditions under which the project plume may be perceived as visible was not required of this project, since there are no state parks and/or historic sites, and airports and/or airstrips within the largest Class II significant impact area (within 5.4 km of the Main Boiler stack).

Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised).*"

Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the coal, ultra low sulfur fuel oil fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

Section 6.0 of the permit application contains discussion of how toxic emissions were determined. For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. Plant Washington referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

Air Toxics Analysis

Maximum ground-level air toxic concentrations were assessed by Plant Wahington using the SCREEN3 model and maximum emission rates from the Main and Auxiliary boilers. Four air contaminants required refined modeled assessment using the ISCST3 model (version 02035) without downwash effects in accordance with the Georgia EPD *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions, 6/98 (Georgia Guideline)*. The maximum 1-hour modeled concentration from each model was multiplied by 1.32 and used for the 15-minute averaging period. Maximum-modeled concentrations for each air toxic pollutant and applicable averaging period are summarized and compared to their respective Acceptable Ambient Concentrations (AACs) and it is found under Table 6-2 of the permit application. The maximum ground-level concentration (MGLC) predicted for each contaminant over it's respective time-weighted averaging period was found to comply with the appropriate AAC.

Plant Washington also assessed the potential additive effects in accordance with the Georgia Guideline. This guidance compares, for each of the three time-weighted averaging periods for which AACs are calculated, the sum of the ratios of each MGLC to it's AAC, regardless of whether each contaminant affects one or more organs in the same way. The additive impacts accounted for in this way totaled 91%, 77%, and 22% of the AAC's for the time-weighted averaging periods of annual, 24-hour, and 15-minute periods, respectively. Since none of these totals exceed 100%, cumulative impacts are not considered to be of concern.

The Air Toxics analysis shows conformance with the Georgia Air Toxics Guideline Acceptable Ambient Concentrations.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-303-0051-P-01-0.

Section 1.0: General Requirements

The following permit conditions were added to standard permit conditions:

Condition 1.6 – General applicability of 40 CFR Part 60, Subpart Da to Coal Fired Boiler, S1.

Condition 1.7 – General applicability of 40 CFR Part 63, Subpart B to Coal Fired Boiler, S1.

Condition 1.8 – General applicability of 40 CFR Part 60, Subpart Db to Auxiliary Boiler, S45.

Condition 1.9 – General applicability of 40 CFR Part 63, Subpart B to Auxiliary Boiler, S45.

Condition 1.10 – General applicability of 40 CFR Part 60, Subpart Y to coal processing and conveying equipment, coal storage systems and coal transfer and loading systems which includes Emission Units A4, S40, S41, S46 and S47.

Condition 1.11 – General applicability of 40 CFR Part 60, Subpart OOO to the Limestone Management Particulate Sources (Emission Units A5, S42 and S48) and associated conveying system.

Condition 1.12 – General applicability of 40 CFR Part 60, Subpart IIII to the Emergency Diesel Generator, EG1 and the Emergency Fire Water Pump, EP1.

Condition 1.13 – General applicability of 40 CFR Part 63, Subpart ZZZZ to the Emergency Diesel Generator, EG1 and the Emergency Fire Water Pump, EP1.

Condition 1.14 – General applicability of 40 CFR Parts 72, 73, 75, 77 to Coal Fired Boiler, S1.

Condition 1.15 – General applicability of 40 CFR Part 68 to Ammonia Storage Tank, TNK4.

Section 2.0: Allowable Emissions

Condition 2.1 details the commencement and completion of construction deadlines as it applies to PSD as detailed in 40 CFR 52.21.

Condition 2.2 details commencement of construction deadline as it applies to the Notice of MACT Approval as detailed in 40 CFR 63 Subpart B.

Condition 2.3 requires the submittal of a Title V Permit application within 12 months of commencing operation as well as the review of potential applicability of 40 CFR Part 64 to applicable emission units.

Condition 2.4 requires installation and operation of Low NOx Burners, Over-fire Air and Selective Catalytic Reduction on Coal Fired Boiler, S1.

Condition 2.5 requires installation and operation of good combustion practices on Coal Fired Boiler, S1.

Condition 2.6 requires installation and operation of Wet Limestone Scrubber on Coal Fired Boiler, S1.

Condition 2.7 requires installation and operation of Duct Sorbent Injection System on Coal Fired Boiler, S1.

Condition 2.8 requires installation and operation of Fabric Filter Baghouse on Coal Fired Boiler, S1.

Condition 2.9 requires installation and operation of Activated Carbon Injection System on Coal Fired Boiler, S1.

Condition 2.10 requires installation and operation of Low NOx Burners and Flue Gas Recirculation on Auxiliary Boiler, S45.

Condition 2.11 defines the fuel type for Coal Fired Boiler, S1.

Condition 2.12 defines the fuel type for Auxiliary Boiler S45 and the startup fuel for Coal Fired Boiler S1.

Condition 2.13 defines emission limits for NOx, CO, PM/PM_{10}, $PM_{2.5}$, SO_2, VOC, Lead, Fluorides, Sulfuric Acid Mist, Mercury, Hydrochloric Acid and Opacity for Coal Fired Boiler S1.

Condition 2.14 defines minimum control efficiency for Wet Limestone Scrubber.

Condition 2.15 defines the maximum heat input rate for Coal Fired Boiler S1.

Condition 2.16 defines emission limits for NOx, CO, PM/PM_{10}, $PM_{2.5}$, SO_2, VOC, Sulfuric Acid Mist and Opacity for Auxiliary Boiler S45.

Condition 2.17 limits the hours of operation of Auxiliary boiler to 876 hours per any twelve consecutive months.

Condition 2.18 requires installation and operation of drift eliminators with a 0.0005% drift for Cooling Tower.

Condition 2.19 requires installation and operation of insertable filter on PRB Conveyor Stackout S46, Illinois # 6 Conveyor Stackout S47 and Limestone Stackout S48.

Condition 2.20 requires installation and operation of baghouse on Coal Crusher House S40, Tripper Decker S41, Fly Ash Mechanical Exhausters S43 and Limestone Preparation Building S42.

Condition 2.21 requires installation and operation of bin vent filter on Fly Ash Silo S37, SO_3 Sorbent Silo S36, Mercury Sorbent Silo S38, Pretreatment Soda Ash Silo S44 and Pretreatment Hydrated Lime Silo S39.

Condition 2.22 requires to take reasonable precautions to prevent fugitive dust from becoming airborne from Coal handling particulate sources (Emission Units A4, A6 to A9), Ash management particulate sources (Emission Units A1 and A3), Gypsum management particulate sources (Emission Unit A2), Limestone management particulate sources (Emission Units A5 and A10) and Roadway particulate sources (Emission Units P1 to P21 and U1 to U15) and requires to use a combination of enclosures, telescopic chutes, lowering wells, dust suppression systems, covering and crusting agents where appropriate.

Condition 2.23 defines the percent opacity limit from the Coal Handling Particulate Sources (Emission Units A4, A6 to A9, S40, S41, S46 and S47).

Condition 2.24 defines PM/PM_{10} emissions limit from Limestone Stackout, S48.

Condition 2.25 defines the percent opacity limit from the Limestone Railcar Unloading Station, A5.

Condition 2.26 defines the percent opacity limit from openings (except for vents) of Limestone Preparation Building, S42.

Condition 2.27 defines the PM/PM_{10} emissions limit from vents of Limestone Preparation Building, S42.

Condition 2.28 defines PM/PM_{10} emissions limit from PRB Conveyor Stackout S46, Illinois # 6 Conveyor Stackout S47, Coal Crusher House S40, Tripper Decker S41, Fly Ash Mechanical Exhausters S43, Fly Ash Silo S37, SO_3 Sorbent Silo S36, Mercury Sorbent Silo S38, Pretreatment Soda Ash Silo S44 and Pretreatment Hydrated Lime Silo S39.

Condition 2.29 defines the percent opacity limit from the Ash Management Particulate Sources (Emission Units A1, A3, S37 and S43) and Gypsum Management Particulate Sources (Emission Unit A2).

Condition 2.30 defines the percent opacity limit from the SO_3 Sorbent Silo S36, Mercury Sorbent Silo S38, Pretreatment Soda Ash Silo S44, Pretreatment Hydrated Lime Silo S39 and Cooling Tower (Emission Units S2 to S35).

Condition 2.31 defines the percent opacity limit from the Roadway Particulate Sources (Emission Units P1 to P21 and U1 to U15).

Condition 2.32 limits the hours of operation of the Emergency Diesel Generator EG1 and the Emergency Fire Water Pump EP1 to 500 hours during any twelve consecutive months.

Condition 2.33 limits the accumulated non-emergency service (maintenance check and readiness testing) time for each of the Emergency Diesel Generator EG1 and the Emergency Fire Water Pump EP1 to 100 hours during any twelve consecutive months.

Condition 2.34 defines the fuel type for emergency diesel generator EG1, and the emergency firewater pump EP1.

Condition 2.35 defines the percent opacity limit from the emergency diesel generator EG1, and the emergency firewater pump EP1.

Section 5.0: Monitoring

Condition 5.1 explains general requirements for the operation of a continuous monitoring system.

Condition 5.2 requires the installation of CEMS for NOx, SO_2, Filterable PM, CO, Hg, oxygen and carbon dioxide and COMS for the Coal Fired Boiler, S1.

Condition 5.3 requires the installation of monitoring devices to monitor the hours of operation of the Auxiliary Boiler S45, the heat input and gross electrical output to the Coal Fired Boiler S1.

Condition 5.4 requires the installation of monitoring devices to monitor the hours of operation during emergency service and the hours of operation in non-emergency service of the emergency diesel generator, EG1 and the emergency fire water pump, EP1.

Condition 5.5 discusses monitoring of the Limestone stackout S48 and the vents of Limestone Preparation Building S42.

Condition 5.6 discusses monitoring of the Limestone Railcar Unloading Station A5 and from openings (except for vents) from Limestone Preparation Building S42.
Condition 5.7 requires installation of monitoring device on the Wet Limestone Scrubber to monitor scrubbant pH.

Condition 5.8 requires installation of monitoring device to monitor H_2SO_4 sorbent injection rate.

Section 6.0: Performance Testing

Condition 6.1 defines general testing requirements.

Condition 6.2 lists methods for the determination of compliance with emission limits listed under Section 2.0.

Condition 6.3 requires the permittee to conduct performance tests on Coal Fired Boiler S1 for VOC, PM, $PM_{2.5,}$ fluorides, sulfuric acid mist, hydrochloric acid and lead.

Condition 6.4 requires the permittee to conduct performance tests on Auxiliary Boiler S45 for NOx, CO, PM, SO_2, VOC, sulfuric acid mist and opacity.

Condition 6.5 requires the permittee to conduct performance tests on Coal Handling Particulate Sources (Emission Units A4, A6 to A9, S40, S41, S46 and S47) and coal conveying systems, for opacity.

Condition 6.6 requires the permittee to conduct performance tests on Limestone stackout S48 and the vents of Limestone Preparation Building S42, for Particulate Matter.

Condition 6.7 requires the permittee to conduct performance tests on the Limestone Railcar Unloading Station A5 and the openings (except for vents) of Limestone Preparation Building S42, for opacity.

Condition 6.8 requires the permittee to conduct performance tests on the PRB Conveyor Stackout S46, Illinois # 6 Conveyor Stackout S47, Coal Crusher House S40, Tripper Decker S41, Fly Ash Mechanical Exhausters S43, Fly Ash Silo S37, SO_3 Sorbent Silo S36, Mercury Sorbent Silo S38, Pretreatment Soda Ash Silo S44, Pretreatment Hydrated Lime Silo S39, for Particulate Matter.

Condition 6.9 requires the permittee to conduct performance test for HF and HCl on the Wet Limestone Scrubber to establish limit for scrubbant pH.

Condition 6.10 requires the permittee to conduct performance test for sulfuric acid mist to establish the minimum value for the sorbent injection rate.

Section 7.0: Notification, Reporting and Record Keeping

Recordkeeping Requirements

Condition 7.1 defines the records maintenance schedule.

Condition 7.2 requires record keeping of the operating hours for the Auxiliary Boiler S45.

Condition 7.3 specifies compliance with diesel fuel oil sulfur content and record keeping.

Condition 7.4 defines frequency of record keeping of fuel burned in the Coal Fired Boiler S1.

Condition 7.5 describes 30-day rolling average determination of NOx emissions from the Coal Fired Boiler S1, and requires recordkeeping.

Condition 7.6 describes 30-day rolling average, 12-month rolling average, 3-hour rolling average and 24-hour rolling average determination of SO_2 emissions from the Coal Fired Boiler S1, and requires recordkeeping.

Condition 7.7 describes 3-hour rolling average determination of Filterable PM emissions from the Coal Fired Boiler S1, and requires recordkeeping.

Condition 7.8 describes 1-hour average and 30-day rolling average determination of CO emissions from the Coal Fired Boiler S1, and requires recordkeeping.

Condition 7.9 describes 12-month rolling average determination of Mercury emissions from the Coal Fired Boiler S1, and requires recordkeeping.

Condition 7.10 requires recordkeeping related to startup and shutdown of the Coal Fired Boiler S1.

Condition 7.11 requires recordkeeping related to continuous emissions monitoring systems, monitoring devices, and performance testing measurements.

Condition 7.12 requires recordkeeping of the heat input rate to the Coal Fired Boiler S1.

Condition 7.13 requires recordkeeping of the gross electrical output for the Coal Fired Boiler S1.

Condition 7.14 discusses recordkeeping related to the cooling tower.

Condition 7.15 discusses recordkeeping of the monitoring of Limestone Stackout S48 and the vents of Limestone Preparation Building S42.

Condition 7.16 discusses recordkeeping of the inspections of dust suppression system to control fugitive emissions from the Limestone Railcar Unloading Station A5 and from openings (except for vents) from Limestone Preparation Building S42.

Condition 7.17 requires to develop and implement a Dust Suppression Plan in accordance with Condition 2.22.

Condition 7.18 requires record keeping of the operating hours for the emergency diesel generator EG1 and the emergency fire water pump EP1.

Condition 7.19 requires recordkeeping to demonstrate compliance with the NSPS Subpart IIII emission limits for the emergency diesel generator EG1.

Condition 7.20 requires recordkeeping to demonstrate compliance with the NSPS Subpart IIII emission limits for the emergency fire water pump EP1.

Reporting Requirements

Condition 7.21 requires submitting notification of the date of construction and actual date of initial startup and certification of construction completion.

Condition 7.22 requires notification of any deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning, or emission control equipment for a period of four hours or more that results in excessive emissions.

Condition 7.23 defines excess emissions.

Condition 7.24 requires to submit a written report containing excess emissions, exceedances, and/or excursions as described in the permit and any monitor malfunctions for each quarterly period.

Condition 7.25 lists excess emissions, exceedances or excursions for reporting requirements.

Condition 7.26 lists the information that needs to be submitted as part of the quarterly report.

Section 8.0: Special Conditions

Condition 8.1 explains Division's right to amend the provisions of the Permit.

Condition 8.2 requires facility to pay an annual permit fee once the plant becomes operational.

APPENDIX A - 112(g) Case-By-Case Maximum Achievable Control Technology Determination

APPENDIX B - Draft SIP Construction Permit Plant Washington

APPENDIX C - Plant Washington PSD Permit Application and Supporting Data

List of Permit Application Supporting Data Documents

1. PSD Permit Application No. 17924, dated January 17, 2008
2. Submitted Additional Information (Modeling), dated March 31, 2008
3. Submitted Revised Application, dated December 3, 2008 (Application dated January 17, 2008 has been replaced by the application dated December 3, 2008)
4. Submitted Updated HF BACT Analysis, dated April 16, 2009
5. Submitted $PM_{2.5}$ BACT Analysis, dated May 13, 2009
6. Submitted Additional Information ($PM_{2.5}$ BACT), dated May 19, 2009
7. Submitted additional information, dated May 28, 2009
8. Submitted Additional Information (Modeling), dated July 27, 2009
9. Submitted Additional Information (Modeling), dated August 4, 2009

APPENDIX D - EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review

APPENDIX E - EPD'S CAMx Photochemical Modeling Review

APPENDIX F - EPD BACT Comparison Spreadsheet for the Coal Fired Boiler S1

APPENDIX G - EPD BACT Comparison Spreadsheet for the Auxiliary Boiler S45