POWER4Georgians

Plant Washington

Prevention of Significant Deterioration Air Permit Application

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LIST OF ACRONYMS AND ABBREVIATIONS

Acronym	**Definition**
ACFM	Actual Cubic Feet per Minute
ACGIH	American Conference of Governmental Industrial Hygienists
AEGI	Amine Enhanced Gas Injection
AERMAP	AERMOD Mapping Program
AERMOD	ARMS/EPA Regulatory Model
AHPC	Advanced Hybrid Particulate Collector
AOI	Area of Impact
AP	Air Pollution
ARMS	AERMOD Retrieval Modeling System
BACT	Best Achievable Control Technology
BART	Best Available Retrofit Technology
BPIP	Building Profile Input Program
Btu	British Thermal Unit(s)
Btu/hr	British Thermal Unit(s) per Hour
$CaCO_3$	Limestone
CAIR	Clean Air Interstate Rule
CALPUFF	(Dispersion Model Name)
CAMR	Clean Air Mercury Rule
CaO	Lime or Pebble Lime
$Ca(OH)_2$	Slaked Lime or Hydrated Lime
$CaSO_3$	Calcium Sulfite
$CaSO_4 \cdot H2O$	Calcium Sulfate (Anhydrite)
$CaSO_4 \cdot 2H2O$	Calcium Sulfate (Gypsum)
CDS	Circulating Dry Scrubber
CEM	Continuous Emission Monitor
cfm	Cubic Feet per Minute
Cl_2	Chlorine
CO	Carbon Monoxide
CO_2	Carbon Dioxide

LIST OF ACRONYMS AND ABBREVIATIONS (Cont'd)

Acronym	**Definition**
COM	Continuous Opacity Monitor
DC	Direct Cost
DDF	Data Decryption Field
DEM	Digital Elevation Model
DEP	Department of Environmental Protection
DRE	Destruction Removal Efficiency dscfm Dry Standard Cubic Feet per Minute
DSI	Dry Sorbent Injection
Dynes/cm	Dyne(s) per Centimeter
EMC	Electric Membership Corporation
EGR	Exhaust Gas Recirculation
ESP	Electrostatic Precipitators
F	Fahrenheit
$FeCl_3$	Ferric Chloride
Fe_2O_3	Iron Oxide
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
FLAG	Federal Land Managers Air Quality Related Values Workgroup
FLGR	Fuel Lean Gas Reburning
FLM	Federal Land Management
ft/sec	feet per second
GA EPD	Georgia Environmental Protection Division
gal/mo	Gallon(s) per Month
g/m^3	Gram(s) per Cubic Meter
gr/dscf	Grain(s) per Dry Standard Cubic Foot
gr/ft^3	Grain(s) per Cubic Foot
g/s	Grams per Second
HAP	Hazardous Air Pollutant
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid

LIST OF ACRONYMS AND ABBREVIATIONS (Cont'd)

Acronym	**Definition**
Hg	Mercury
HNO_3	Nitric Acid
hp	Horsepower
H_2SO_4	Sulfuric Acid
IC	Indirect Cost
ID	Identification
in/yr	inch per year
IPPC	Integrated Pollution Prevention and Control
ISC	Industrial Source Complex
ISCST3	Industrial Source Complex Short Term
kPa	Kilopascals
kV	Kilovolts
kWh	Kilowatt Hours
LAER	Lowest Achievable Emission Rate
lb/MMBtu	Pound(s) per Million British Thermal Unit
lb/MMscf	Pound(s) per Million Standard Cubic Feet
LCC	Lambert Conformal Coordinate
LEA	Low Excess Air
LNB	Low NO_X Burner
m3	Cubic Meters
MACT	Maximum Achievable Control Technology
MACTEC	MACTEC Engineering and Consulting, Inc.
$\mu g/m^3$	Microgram(s) per Cubic Meter
mg/dscm	Milligram(s) per Dry Standard Cubic Meter
MGLC	Maximum Ground-level Concentration
mg/L	Milligrams per Liter
mg/m^3	Milligram(s) per Cubic Meter
MMBtu/hr	Million British Thermal Unit(s) per Hour
MMcf	Million Cubic Feet

LIST OF ACRONYMS AND ABBREVIATIONS (Cont'd)

Acronym	**Definition**
MW	Megawatts
NAAQS	National Ambient Air Quality Standard
Na_2CO_3	Sodium Carbonate
NAICS	North American Industry Classification System
NaOH	Sodium Hydroxide
NESHAP	National Emissions Standards for Hazardous Air Pollutants
ng/J	nanogram per Joule
NGR	Natural Gas Reburning
NH_3	Ammonia
NH_4SO_4	Ammonia Sulfate
NOV	Notice of Violation
NO_x	Nitrogen Oxide
NO_2	Nitrogen Dioxide
N_2O_5	Nitric Pentoxide
NSCR	Non-selective Catalytic Reduction
NSR	New Source Review
NSPS	New Source Performance Standard
NWS	National Weather Service
OFA	Over-fired Air
OSHA	Occupational Safety and Health Administration
PAC	Powdered Activated Carbon
Pb	Lead
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter Less Than 2.5 Microns
PM_{10}	Particulate Matter Less Than 10 Microns
ppm	Part(s) per Million
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
psia	Pound(s) per Square Inch Acceptable/Atmospheric

LIST OF ACRONYMS AND ABBREVIATIONS (Cont'd)

Acronym	**Definition**
psig	Pound(s) per Square Inch Gauge
PSM	Process Safety Management
RACT	Reasonably Achievable Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RMP	Risk Management Programs
ROFA	Rotating Opposed Fire Air
RTO	Regenerative Thermal Oxidizer
SAIL	Significant Ambient Impact Level
SAM	Sulfuric Acid Mist
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SCRAM	Support Center for Regulatory Air Models
SDA	Spray Dryer Absorption
SDTS2DEM	Spatial Data Transfer Standard 2 Digital Elevation Model
SIA	Significant Impact Area
SIL	Significant Impact Level
SIP	State Implementation Plan
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SO_4	Sulfate
SCPC	Supercritical Pulverized Coal
T/hr	Tons per hour
TDS	Total Dissolved Solids
TLV	Threshold Limit Value
TWA	Time-weighted Average
ULNB	Ultra-low NOx Burner
USEPA	US Environmental Protection Agency
USGS	US Geological Survey

LIST OF ACRONYMS AND ABBREVIATIONS (Cont'd)

Acronym	**Definition**
USNPS	National Park Service
UTM	Universal Transverse Mercator
VISCREEN	Visibility Screening Model
VISTAS	Visibility Improvement – State and Tribal Association of the Southeast
VOL	Volatile Organic Liquid
VOC	Volatile Organic Compound
WESP	Wet Electrostatic Precipitator
WFGD	Wet Flue Gas Desulfurization

QUALITY CONTROL SIGNATURE PAGE

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1.0 INTRODUCTION

Plant Washington is being developed by Power4Georgians, LLC, a consortium of 10 electric membership cooperatives (EMCs) in Georgia, to provide reliable and affordable electricity. Review of the future power demands indicates a 5 percent per year increase in demand demand due to changes in population beyond the current nearly 700,000 commercial and residential members. The facility will have one unit with a total net generating capacity of 850 megawatts (MW). The proposed unit is intended to be operational in June 2013.

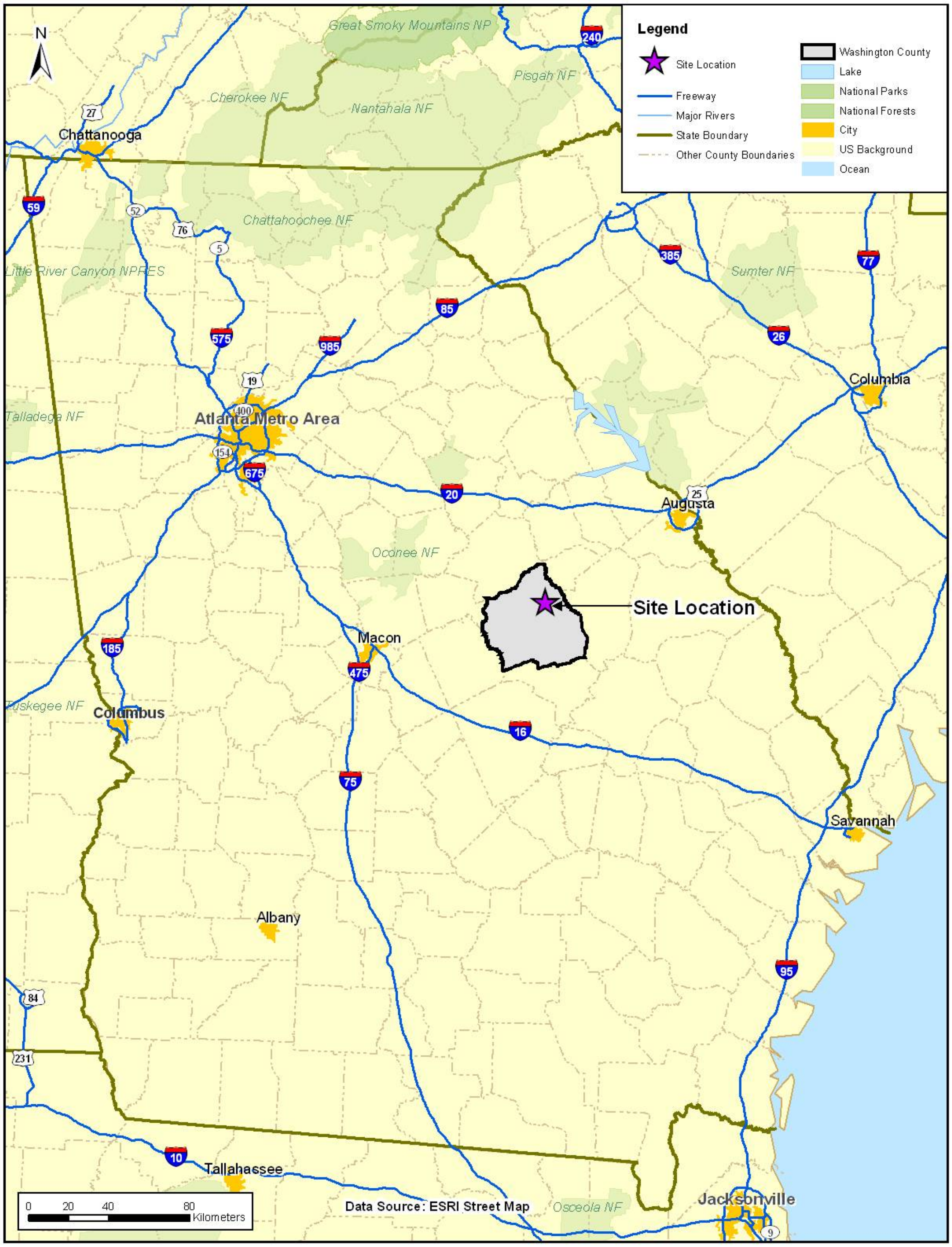
The proposed location for Plant Washington is a 1,134-acre site in Washington County, northeast of the City of Sandersville, Georgia. Figures 1-1 and 1-2 show the approximate location of the planned project site near Sandersville. The facility will employ 100 to 150 people and will consist of the power block, office areas, rail service approach and rail sidings, and looped 500-kilovolt (kV) power transmission lines. In addition, a solid materials handling and storage facility will be maintained on-site for storage of coal, limestone, gypsum, and bottom/fly ash. The plant will also have various water storage basins to hold raw water, wastewater effluent, and stormwater runoff.

The proposed project consists of one Supercritical Pulverized Coal (SCPC) fired steam generating unit and associated steam turbine generators along with other auxiliary equipment. The generating plant will be rated at approximately 850 MW net output capacity, and will be designed to burn up to a 50/50 blend of western sub-bituminous coal (Powder River Basin, or PRB coal) and eastern bituminous coal (Illinois #6). Supercritical power plants use a boiler/turbine system that operates at much higher pressure and temperature steam (3200 pounds per square inch gauge [psig] and 1,075° Fahrenheit [F]) versus subcritical plants that generally operate at much lower steam temperatures (2,400 psig and 850°F being typical). This makes a supercritical plant much more efficient than a subcritical plant, producing more power from the less coal and with lower emissions.

The project will be a major source of air emissions under the Prevention of Significant Deterioration (PSD) program of New Source Review (NSR) rules, so this application contains all the appropriate analyses required under that program. All proposed control equipment and emission limits at the facility have been selected based on a Best Available Control Technology (BACT) analysis. The facility will be equipped with Continuous Emission Monitors (CEMs) that will monitor and record pollutant emissions as required under State and Federal regulations. Proposed equipment in use at the facility will include:

- One coal-fired electric utility steam generating unit with a rated heat input of 8,300 million British Thermal Units per hour (MMBtu/hr) utilizing a supercritical cycle design, which will be equipped with low nitrogen oxide (NO_X) burners, overfire air, Selective Catalytic Reduction (SCR), a fabric filter baghouse, and a Wet Flue Gas Desulfurization (WFGD) System. In addition, emission controls will include sorbent injection systems for the control of sulfuric acid (H_2SO_4) mist and mercury (Hg) emissions.
- A steam turbine and associated generator.
- Facilities for receiving, handling, storing, blending, and processing two types of coal, PRB and Illinois #6, with as much as 431 tons per hour (T/hr) of blended coal or at a rate of 490 T/hr when burning only PRB coal.
- Facilities for receiving, handling, and storing anhydrous ammonia, which is a raw material for the SCR system.
- Facilities for receiving, handling, storing and process limestone, which is a raw material for the WFGD system.
- Facilities for receiving, handling, storing and delivering mercury removal adsorbent (sorbent) and sulfur trioxide (SO_3) removal sorbent (for the control of Sulfuric Acid Mist [SAM] emissions).
- A solids material handling facility (SMHF) for handling and storing process byproducts.
- Facilities for on-site storage of process wastes for potential reuse.
- An emergency diesel-fired generator.
- A diesel engine driven fire pump.
- A 240 MMBtu/hr No. 2 fuel oil fired auxiliary boiler.

Figure 1-1 Plant Washington Site Vicinity Location



Data Source: ESRI Street Map

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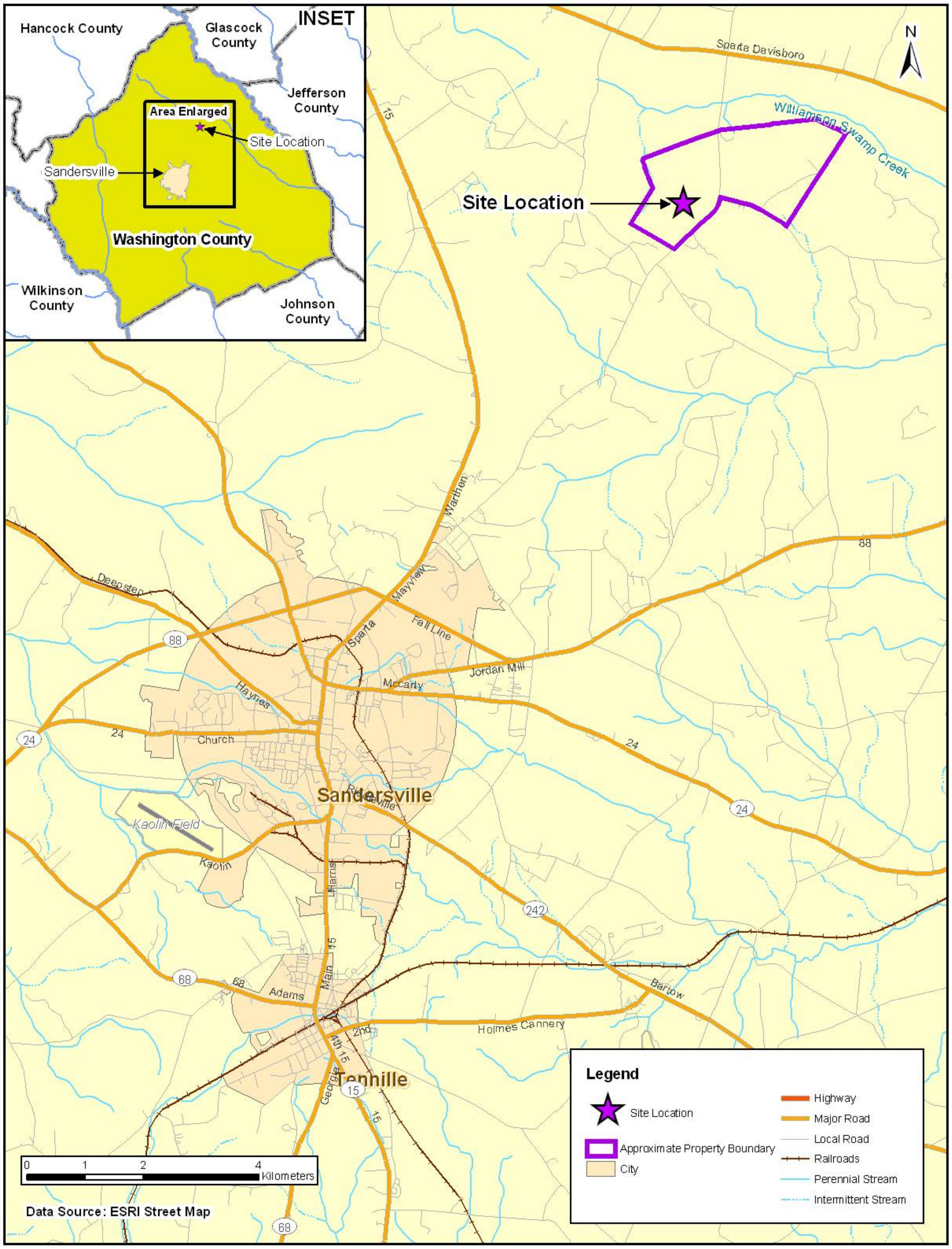
Figure 1-2 Plant Washington Approximate Site Location



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This air permit application includes a process and project description (Section 2), an emission calculation summary and regulatory analysis of the proposed project (Section 3), a BACT analysis (Section 4) for the affected equipment, the required National Ambient Air Quality Standard (NAAQS) and PSD air quality modeling analyses (Section 5), Georgia Air Toxics Modeling (Section 6), Class I Area modeling (Section 7), Class II visibility and an other impacts analysis (Section 8), and the required Georgia Environmental Protection Division (GA EPD) permit application forms (Section 9).

The application also includes the following exhibits: emission calculations (Exhibit A) that form the basis of the permitting approach and modeling assessments, the site layout (Exhibit B), air quality modeling information (Exhibit C), and an electronic copy of models (Exhibit D).

1.1 Power Demand For Georgia

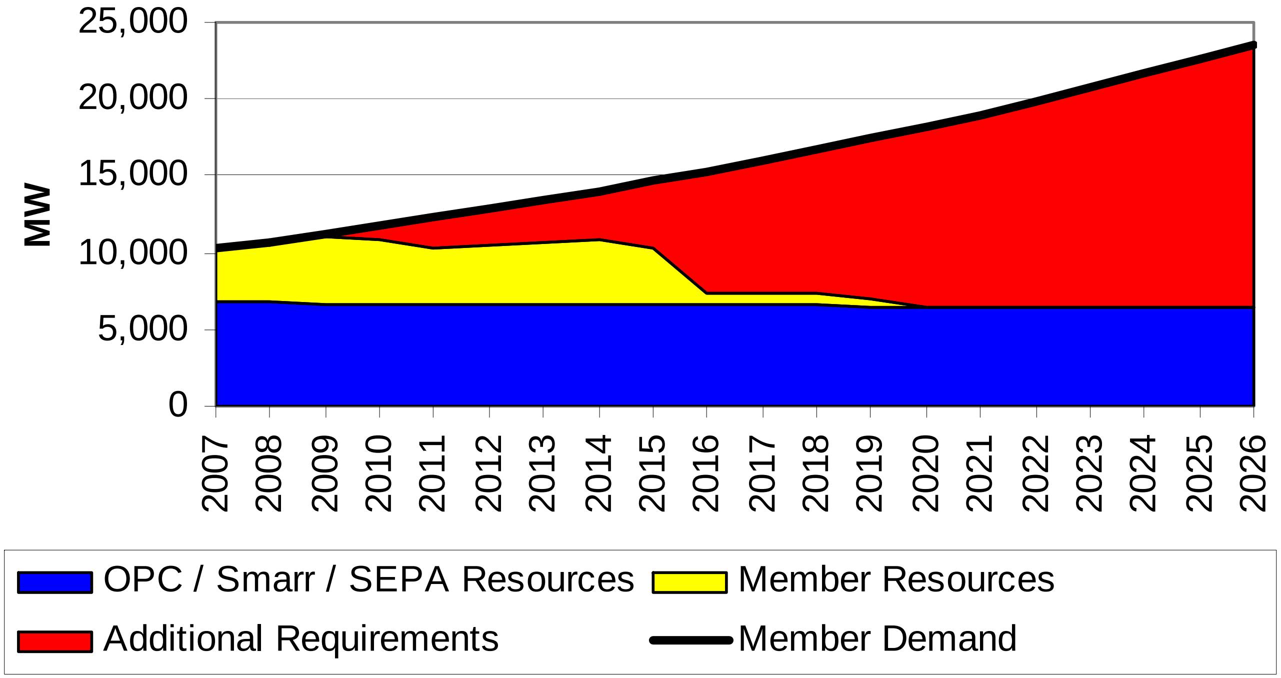
Power4Georgians, LLC, is a company formed to ensure that Georgians will continue to have reliable electric power in the coming years. The company consists of 10 Georgia EMCs that have pooled their resources to construct a baseload power generating facility in middle Georgia. Power4Georgians, LLC, will be the legal entity developing the power plant. The 10 EMCs and their locations are: Upson EMC, Thomaston; Central Georgia EMC, Jackson; Snapping Shoals EMC, Covington; Diverse Power, LaGrange; Excelsior EMC, Metter; GreyStone Power, Douglasville; Jackson EMC, Jefferson; Cobb EMC, Marietta; Pataula EMC, Cuthbert; and Washington EMC, Sandersville. All of these EMCs have independently concluded that, despite efforts in promoting energy conservation, power demand will substantially increase in the years ahead. Although power demand is increasing, the supply of power that the EMC have contracts for will be decreasing, and by the year 2013 the EMCs will have a large gap to fill between the growing demand and the loss of available power. Figure 1-3 shows the increasing demand curve and the reduction of available power. Plant Washington will be a significant supply to fill this energy gap coming in the near future. The other portion of the solution is to rely on continued conservation efforts of the membership and the EMCs' alternative energy sources, such as the biomass plant in Bleckley County.

Power4Georgians, LLC, is exploring all sources of energy including natural gas, wind, solar, and biomass (such as on-site storage of methane gas, wood chips, and poultry litter-to-energy) to ensure a reliable energy supply. Many of the co-ops in this project participate in Georgia's Green Power EMC and make green energy available to members. Power generated by Green Power EMC helps meet peak demand but is not sufficient to meet baseload demand.

In reviewing options to meet power requirements, the members of this coalition investigated other possible options for baseload. Two potential options, which could provide substantial capacity of baseload, were considered. One is Plant Vogtle's expansion, which will occur in 2016 or later. Consortium members are currently taking power from the existing units, and the current forecast assumes that the Consortium will participate in the expansion; however, the Consortium's baseload needs must be met before any supply is available from Vogtle.

At the moment, the progress on the proposed power plant in southwest Georgia has been halted until resolution of an anticipated appeal of a court ruling regarding the air permit. Depending on the outcome of the appeal and various other business issues, that plant could meet some of our needs for baseload, but even with proposed plant capacity, the ten members would be deficient in baseload capacity; therefore, it is necessary for this group (due to reliability and demand requirements) to construct a baseload coal plant. Additional options using renewable and solar energy sources have been investigated, contracted for, and partially implemented. Portions of the load will be served by these energy sources; however, there is not enough capacity to cover our member's energy needs within Georgia.

Figure 1-3 EMC Projections of Power Demand and Availability



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2.0 PROCESS DESCRIPTION

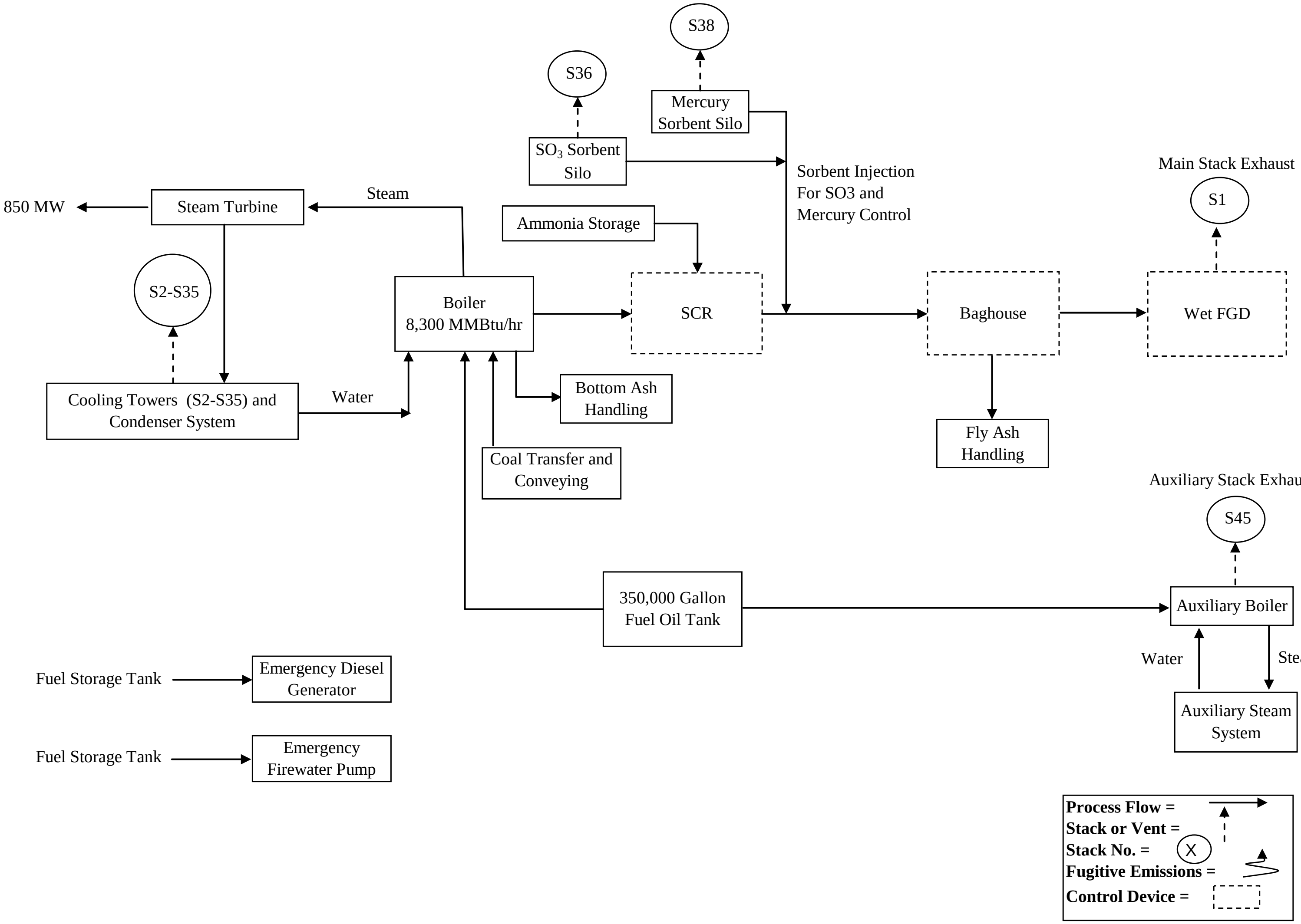
Power4Georgians, LLC proposes to construct and operate a new power generation facility in Washington County near Sandersville, Georgia. The proposed project consists of one SCPC fired steam generating unit and associated steam turbine generators along with other auxiliary equipment. The generating plant will be rated at approximately 850 MW net output capacity, and will be designed to burn up to a 50/50 blend of western sub-bituminous coal (Powder River Basin, or PRB coal), and eastern bituminous coal (Illinois #6). The unit will be normally 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). The steam will be expanded through a high pressure steam turbine section, then reheated and expanded in intermediate and low pressure turbine sections to drive an electric power generator.

A blend of coals is being proposed for two reasons: 1) to ensure reliability of receipt of the daily coal shipments needed to keep the plant operational and 2) eastern coal is more cost effective when considering the transportation cost of obtaining the coal. Both Powder River Basin (PRB) and Illinois #6 coals will be brought to the facility by bottom dump railcars. Coal will be unloaded from the railcars at the railcar unloading facility and sent to the PRB and Illinois #6 active coal piles, with a portion of the coals being sent to the PRB and Illinois #6 inactive coal piles in order to accommodate for interruptions in the fuel supply. Coal will be pulled from the PRB and Illinois #6 coal piles, blended to a 50/50 coal blend, and sent to the crushers where the coal is crushed and pulverized. Crushed coal will be fed to conveyors and transferred to fuel storage silos.

Pulverized coal will then be combusted in the facility main boiler, an 850 MW net output capacity steam generating unit. 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. Emissions from the main facility boiler will be controlled by air pollution control equipment prior to discharge from the main boiler stack. The air pollution control equipment in use on the main boiler will include a SCR system for control of NO_X emissions, sorbent injection systems for the control of H_2SO_4 and mercury emissions, a fabric filter for the control of Particulate Matter (PM) emissions, and an WFGD for control of sulfur dioxide (SO_2) emissions. Additional pollutants will be controlled through use of the above discussed air pollution control equipment, which will be discussed further in the BACT analysis in Section 4 of this application.

The following Figure 2-1 provides an overall process flow diagram of the facility operations surrounding the main facility boiler.

Figure 2-1 Overall Process Flow Diagram



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2.1 Process Description for the Power Boiler

The SCPC fired boiler will be a pulverized coal single reheat, wall fired dry bottom boiler with low NO_X burners and overfire air. The unit will be a Babcock & Wilcox boiler designed to produce very high pressure steam while minimizing the formation of NO_X in the combustion process. NO_X formation is minimized by the use of air staging. Overfire air is injected to the furnace in several different levels. This in effect divides the furnace volume in three different zones: 1) the primary firing zone, 2) the NO_X reduction zone and 3) the final burnout zone. The maximum heat input rate of the boiler will be approximately 8300 MMBtu/hr (while firing coal). Actual heat input and generator production will depend on a variety of operating variables, including ambient temperature and pressure and the condition of equipment associated with boiler operation. 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.

Flue gas from the boiler will be passed through a series of control devices. After leaving the furnace and an air heater, the economized hot flue gases will be sent to two SCR system reactor chambers operating in parallel for the control of NO_X. Anhydrous ammonia, stored in pressurized tanks will be injected into the SCR absorbers as the chemical agent for driving the NO_X reduction reaction (ammonia combines with the NO_X in the exhaust gas to ultimately form nitrogen and water vapor). From the SCR chambers the exhaust gases will be directed through an air preheater to recover heat before being sent on to a baghouse to control particulate emissions. Prior to entering the baghouse, the adsorbents will be injected into the exhaust gas stream. One adsorbent (activated carbon) is used to absorb the small amount of elemental Hg vapor in the exhaust air while the second adsorbent reacts with SO_3 in the exhaust air to prevent sulfuric acid mist formation further downstream. The baghouse removes both the fly ash in the exhaust gas and the absorbents that were added and the reaction products of the adsorbents. The gas then passes through induced draft fans. Finally, the exhaust gas passes through a wet limestone scrubber to remove the SO_2 in the gas before being exhausted out the main stack (S1).

Boiler Start up Procedures

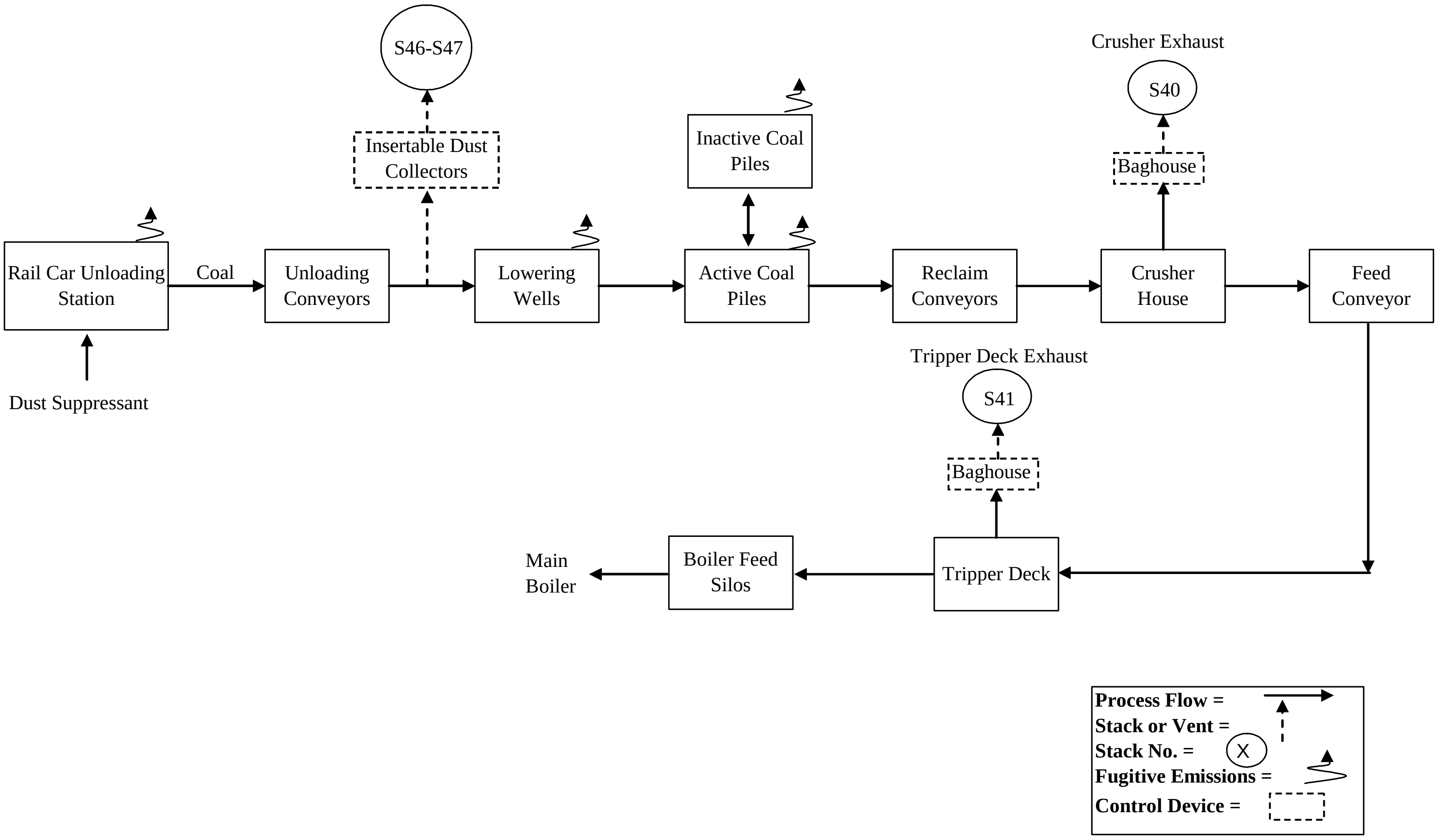
The startup procedure for the main facility boiler will include a 15 hour startup cycle, beginning with the main facility boiler utilizing ultra low sulfur No. 2 distillate fuel oil. The combustion of oil is used to slowly warm the boiler systems to reduce thermal stresses on the boiler system during startup. At the same time the auxiliary boiler produces steam to feed the steam turbine so that it can be slowly brought up to full load. During the entire start up process, the fabric filter baghouse is used for control of PM emissions; and the wet flue gas desulfurization system (wet scrubber or WFGD) used for control of SO_2 emissions will be in service. However, the SCR system, used for control of NO_X emissions, will not be in operation during the startup procedure since the process is ineffective until the exhaust gas (and equipment) reaches a minimum temperature of 450 degrees F. Coal will begin to be introduced to the main 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.

2.2 Process Description for Coal Handling

Figure 2-2 provides a process flow diagram for the coal handling activities. At the railcar unloading facility, coal is dumped into four receiving hoppers which discharged onto 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 dust suppression mixture used at the unloading station will have residual dust suppression characteristics, will remain on the coal for approximately two weeks, and will be applied as necessary to adequately control fugitive dust. During periods of precipitation and/or high humidity, application of the dust suppressant mixture may be discontinued, or a water spray application may be used instead of the chemical mixture as conditions warrant.

The unloading belt feeders will transfer onto the unloading conveyor which conveys coal to the transfer point above the Lowering Well. From this transfer point, PRB coal will be dumped into the PRB Lowering Well. When unloading Illinois #6 coal, the coal will be routed to the Illinois #6 Lowering Well via the Transfer/Storage Conveyor. At the lowering wells, the coal will be stacked out to the respective active coal storage piles. In order to accommodate interruptions of fuel supply, the coal handling system includes inactive coal storage piles for both PRB and Illinois #6 coals located adjacent 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. Sixty days of storage will be maintained on-site for both types of coal including active and inactive storage.

Figure 2-2 Coal Handling Process Flow Diagram



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Coal is pulled from the active storage piles via eight grizzly hoppers and feeders to two Reclaim Conveyors. 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. The conveying system includes a fugitive dust collection system called "insertable dust collector" (emission points S-46 & S-47 for PRB and Illinois 6 coal respectively) and a tramp metal cleaning system.

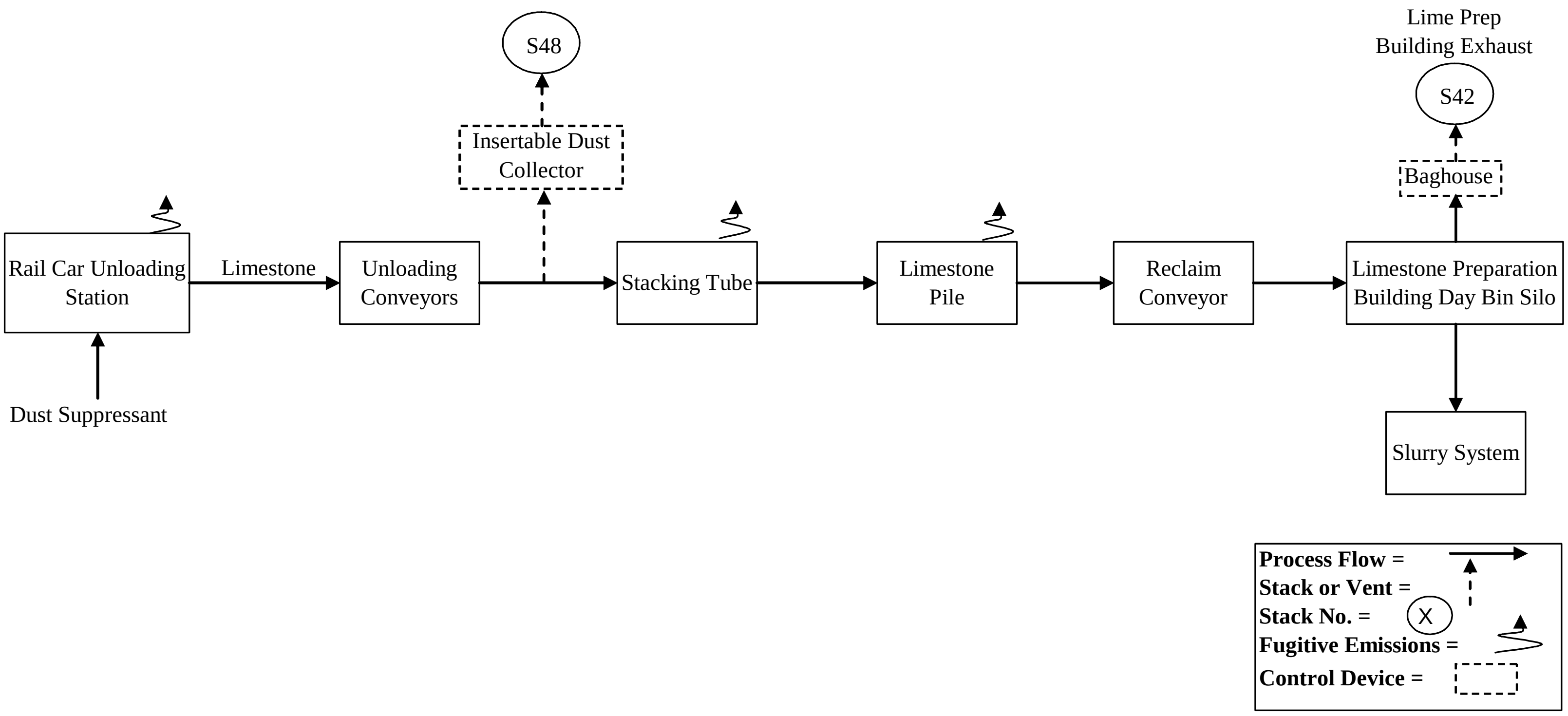
Coal will be conveyed to the Crusher Surge Bin on Reclaim Conveyors 1 and/or 2. In the Crusher House, the coal will be fed from the surge bin to two diverters with fixed grizzlys. From the diverters, the coal is routed to two crushers where the coal is crushed. Dust created from the crushers is controlled by a baghouse (emission point S-40). Coal fines will be bypassed around the crushers. The crushed coal will be fed from the crushers to two conveyors, Feed Conveyors 1 and 2. The coal is then distributed to boiler Silo Fill Conveyors 1 and 2 in the Boiler Silo Bay. Silo Fill Conveyors 1 and 2 will be outfitted with traveling trippers used to fill each of the 6 boiler silos for feed to the pulverizers. All the emissions from the conveyors and tripper are controlled by a single baghouse (emission point S-41).

2.3 Process Description for Limestone Handling

Figure 2-3 provides a process flow diagram for the limestone handling activities at the facility. Limestone will be delivered to the site by bottom-dump railcars for use in the WFGD system. At the limestone unloading station, limestone is dumped into four receiving hoppers which discharge onto dual Unloading Belt Feeders. The unloading station will be enclosed and will utilize a dust suppression system similar to that in the coal unloading facility. In the limestone unloading facility, the Unloading Belt Feeders will dump onto the Limestone Unloading Conveyor which conveys limestone to the Limestone Stacking Tube where it is stacked out to the Limestone Storage Pile.

Limestone will be pulled from the storage pile via two grizzly hoppers with vibrating feeders to a single Limestone Reclaim Conveyor. The Reclaim Conveyor will deliver the limestone to the day bin silo located at the limestone reagent preparation area (air exhausted from the bin vent filter point S-42). The conveying system will include a dust collection system called an "insertable dust collector" (emission point S-48), belt scale and a tramp metal cleaning system.

Figure 2-3 Limestone Handling Process Flow Diagram



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2.4 Process Description for Fly Ash Handling

Figure 2-4 provides a process flow diagram for handling fly ash at the facility. The fly ash system will pneumatically convey dry free flowing ash from the pulse jet fabric filter (baghouse) hoppers and air heater hoppers to the fly ash Storage Silo, which will have a storage capacity of 3600 tons (5-6 days storage). Fly ash will be stored in the silo until load-out to trucks for transfer to the on-site storage facility. The fly ash handling system will be designed to include a vacuum system to transfer ash from the baghouse and air heater hoppers to a filter separator (exhaust point S-43) and fly ash silo, and an ash truck load out station from ash silo pugmills which uses water for dust control. The fly ash handling system serving the baghouse and air heater systems will have a conveying capacity of approximately 50 tons per hour.

The fly ash storage silo will be equipped with a bin vent dust filter, and fly ash mixing/conditioning equipment. Conveying air will be exhausted from the silo through the bin vent filter located at the top of the silo which removes suspended particulates. The silo and associated bin vent filter will be designed with sufficient bag filtering capacity to support operation of fly ash transport. Each bag filter will operate with an air-to-cloth ratio of approximately 2 to 1 during normal operation. The air-to-cloth ratio is well within the range of optimum performance of the pulse jet bag filter. The silo will vent from the bin vent filter with side exhausts (S-37)

The fly ash storage silo is equipped with a fluidizing air system including the porous fluidizing media, two blowers, and two electric air heaters to enhance gravity flow of ash from the bottom of the silo. Fly ash destined for storage will be conditioned by wetting with water as it is unloaded from the silo to minimize dust generation. The conditioned ash will be unloaded through a chute into trucks for transportation to an on-site storage facility. The system will employ redundant features to ensure dependable operation, including a spare vacuum mechanical exhauster and fluidizing blower. The silo and its associated equipment (fly ash conditioner and automatic bin vent filter) will be designed to accommodate the fly ash from the boiler.

2.5 Process Description for Bottom Ash Handling

Figure 2-5 provides a process flow diagram for the bottom ash handling activities at the facility. The bottom ash handling system collects boiler bottom ash and pyrites from the coal pulverizers for

Figure 2-4 Fly Ash Handling Process Flow Diagram

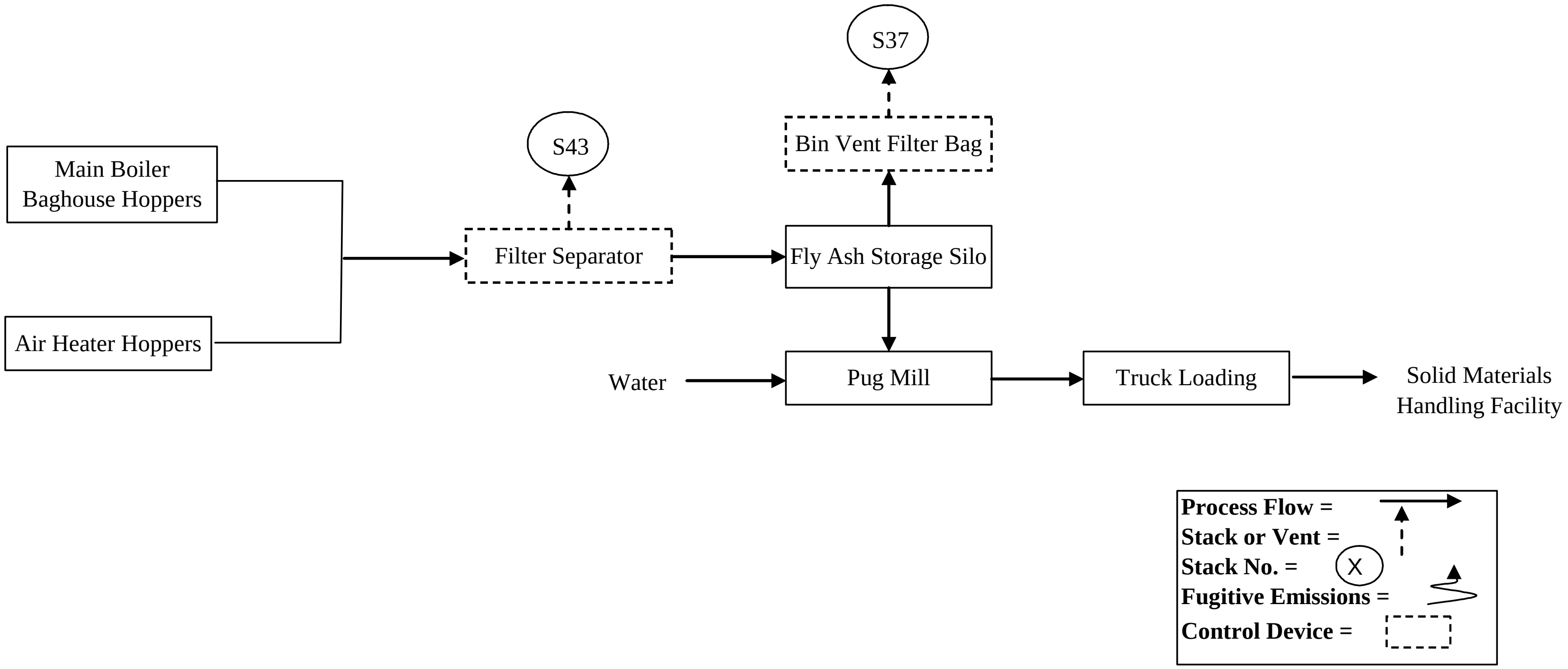

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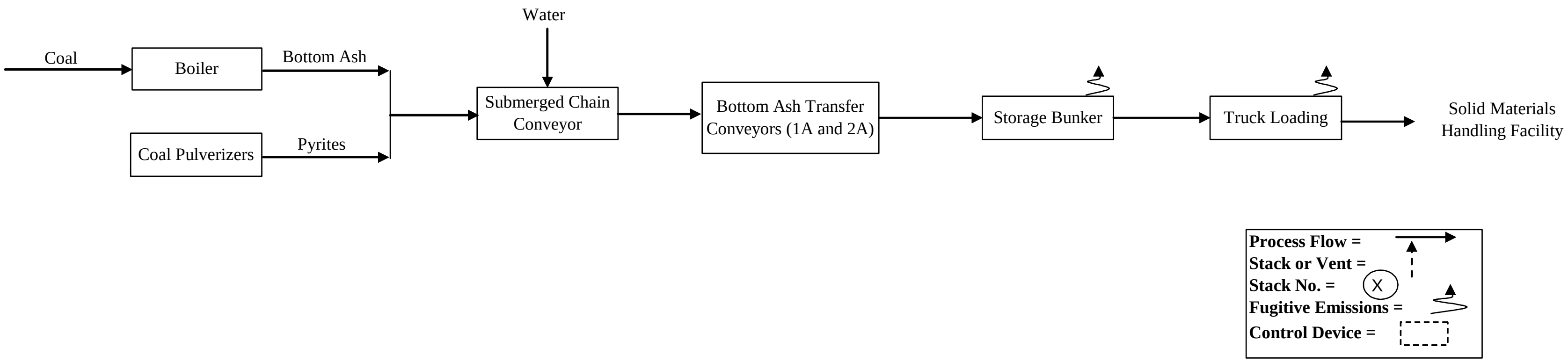
Figure 2-5 Bottom Ash Handling Process Flow Diagram



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Checked by: <u>SAK 1/10/08</u>

disposal. The bottom ash from the boiler furnace is collected in the submerged chain conveyor. The pyrites are sluiced from the pulverizers and fed into the submerged chain conveyor. The drag chain conveyor discharges onto bottom ash transfer conveyor 1A. Bottom ash transfer conveyor 1A discharges onto bottom ash transfer conveyor 1B. Bottom ash transfer conveyor 1B discharges into a three sided ground level bunker for disposal. From the bunker the bottom ash is loaded onto trucks using mobile equipment for transfer to the on-site storage.

2.6 Process Description for Gypsum Handling

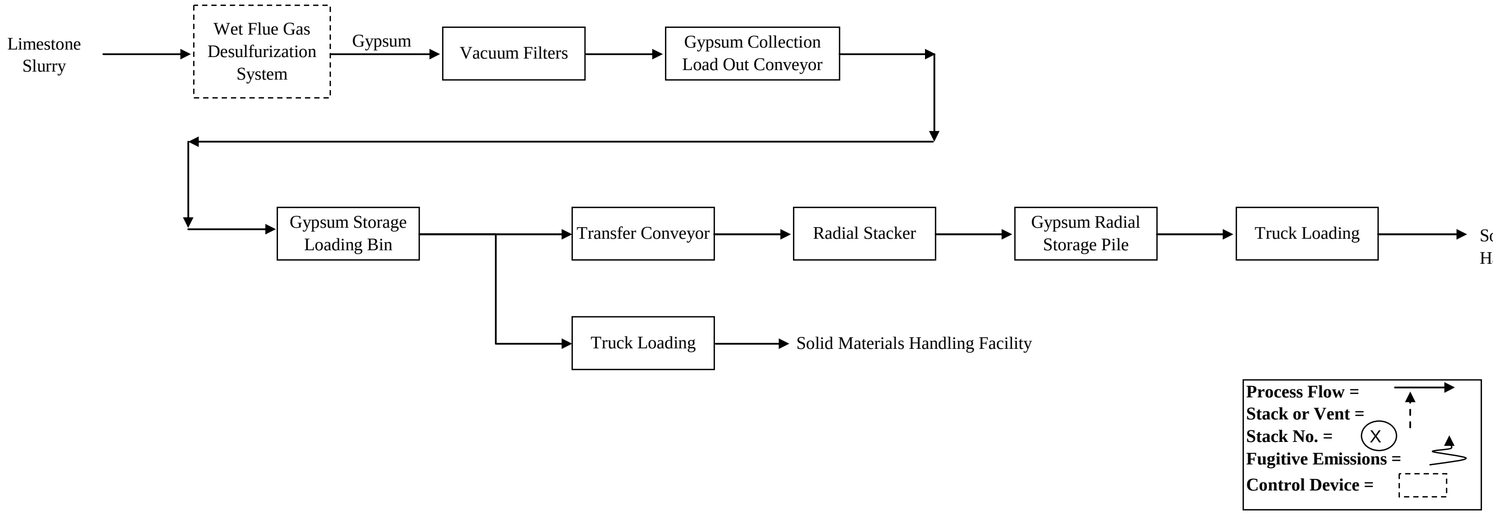
Figure 2-6 provides a process flow diagram for the gypsum handling operations. Operation of the WFGD scrubber will produce gypsum as a by-product, which will be transported to the on-site long term storage facility together with the bottom ash and fly ash. Vacuum belt or drum filters will dewater the gypsum to a free moisture content of approximately 15 to 20 percent. Two vacuum filters will transfer dewatered gypsum onto the Gypsum Collection/Load-out Conveyor. This conveyor will transfer gypsum to the Gypsum Storage/Loading Bin, which at a capacity of 800 tons will hold approximately 10 days worth of gypsum production.

Trucks will be loaded out from the bypsum storage/loading bin during periods when trucks are operating and transporting gypsum to the on-site 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 (i.e. nights, weekends, and emergency situations). The piled gypsum will be loaded onto trucks when operations resume using mobile equipment and removed to the on-site storage.

2.7 Process Description for Anhydrous Ammonia

Anhydrous ammonia storage and handling facilities associated with the SCR system will be installed as part of the project as shown in Figure 2-1.. The ammonia unloading facilities will be equipped with vapor recovery whereby vapors will vent back to the host tank when transferring ammonia. The ammonia will be stored in pressurized storage tanks each with an emergency relief valve. From the storage tanks the ammonia will be piped to the SCR system for injection and mixing in the flue gas upstream of the catalyst layers. 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.

Figure 2-6 Gypsum Handling Process Flow Diagram



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Checked by: SAK 1/10/08

2.8 Process Description for SO_3 and Mercury Sorbents

The air quality control system of the plant will include sorbent injection systems for capture of Hg and SO_3 for control of sulfuric acid mist emissions. Systems to handle these materials will incorporate self unloading of trucks and pneumatic conveying of the sorbents to their respective storage silos. The sorbent storage silos will be equipped with bin vent filters designed with sufficient bag filtering capacity to support sorbent unloading operations. Conveying air from the self unloading trucks is exhausted from the silo through the bin vent filters located at the top of the silos to separate suspended particulates and return them to the silo. Emissions from these silos are expected to occur only during filling operation at a maximum of one hour per shift.

2.9 Process Description for the Pretreatment Soda Ash Silo and the Pretreatment Lime Silo

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 (i.e. cooling tower) at the facility. The lime and soda ash will precipitate iron and phosphorous and removed in a clarifier system. Systems to handle these materials will incorporate self unloading of trucks and pneumatic conveying of the soda ash and lime to their respective storage silos. The soda ash and lime storage silos will be equipped with bin vent filters designed with sufficient bag filtering capacity to support material unloading operations. Conveying air from the self unloading trucks is exhausted from the silo through the bin vent filters located at the top of the silos to separate suspended particulates and return them to the silo.

2.10 Process Description for the Auxiliary Boiler

The plant will be served by an auxiliary boiler to provide steam for startup and other operations as required when steam from the boiler is unavailable or inadequate to supply auxiliary steam equipment needs as shown in Figure 2-1. The auxiliary boiler will be fired on low sulfur No. 2 fuel oil and will have a maximum gross heat input of 240 MMBtu/hr. The auxiliary boiler will be equipped with low NO_X burners and Flue Gas Recirculation (FGR). The exhaust from the auxiliary boiler will be emitted through a stack. Operation of the auxiliary boiler will be limited to a ten percent annual capacity factor based on heat input. During the initial plant commissioning activities, the auxiliary boiler may operate more than the 10 percent capacity factor over the first 12 months.

2.11 Process Description for the Emergency Equipment

The plant configuration, as indicated in Figure 2-1, will include an emergency diesel generator, which will be used for shutdown or other operations when normal power supply to plant equipment is interrupted. The generator engine will be fired on diesel fuel and its output will be approximately 1,120 kw. It is anticipated that the generator will not be operated for more than 500 hours per year as it will be for emergency use and maintenance/testing operations only. The generator will be equipped with a small, approximately 2,000 gallon capacity diesel storage tank.

The plant will also include a diesel driven emergency fire water pump. The pump engine will be fired on diesel fuel and its output will be approximately 350 hp. It is expected the emergency fire water pump will not be operated for more than 500 hours per year as it is only for emergency use and maintenance/testing.

2.12 Process Description for the Cooling Tower

The cooling tower will be a multi-celled, back-to-back style tower. The purpose of the cooling tower is to cool the water that is circulated in the heat exchangers that condense the steam from the steam turbine. The cooling tower will be comprised of 34 cells using drift eliminators for the reduction of drift (the amount of water from the cooling tower carried into the ambient air in liquid form) (emission points S-2 through S-35). Mineral salts present in the water droplets released in the drift form PM as the water droplets evaporate in the air. So in order to reduce the amount of particulated generated in this manner, the cooling tower will be equipped with drift eliminators designed to limit drift to 0.0005 percent of the cooling tower water flow. A water minimization plan will in place at the plant with a goal to reuse water as much as possible. Even with this plan in place the total dissolved solids (TDS) in the cooling tower water is expected to be maintained at less than 3300 ppm.

2.13 Process Description for the Solid Materials Handling Facility for Long Term Storage

The facility will maintain a long-term storage facility on site for solid material produced by the plant namely gypsum and fly ash. The materials will be loaded into trucks from the appropriate storage silo in the main operational areas of the facility and transported to the on-site storage. The trucks will unload the solid materials into an active “cell” of the SMHF. There will be separate storage areas for the gypsum and the fly ash. It is planned that the fly ash can be sold to concrete production facilities and the gypsum used to produce wall board.

2.14 Plant Production Capacity

The maximum annual coal consumption of the main facility boiler is 431 ton/hr, or 3.78 x 10^6 ton/yr. The maximum anticipated power output of the facility is 850 MW net.

3.0 REGULATORY ANALYSIS

3.1 PSD Applicability Analysis

The Power4Georgians facility will emit more than 100 tons per year of several PSD pollutants including PM_{10}, VOC, NO_x, CO, and SO_2; therefore, the facility will be considered a major source under the PSD program since it is one of the 27 industrial categories (fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input). The facility will be located in Washington County, which is currently designated as an attainment area for all criteria pollutants. Before the proposed project can be permitted, it must be evaluated according to a PSD applicability analysis, and, if the project exceeds significant impact levels, a PSD review must be completed for each significant pollutant.

In December 2002, the United States Environmental Protection Agency (USEPA) enacted rules that changed the NSR program. This permit application, therefore, has been prepared under the new PSD rules. The first step is to evaluate the potential emissions for all regulated pollutants. As shown in Table 3-1, the proposed project may result in a PSD significant increase for PM_{10}, NO_x, CO, VOC, SO_2, Pb, Fluorides, and H_2SO_4 Because this will be a new facility, there will be no contemporaneous reductions of emissions to offset these increases, so the project triggers a PSD review for PM, NO_x, CO, VOCs, SO_2, Pb, Fluorides, and H_2SO_4. Also, although Hg emissions are not subject to PSD review per *40 CFR 52.21 Prevention of Significant Deterioration of Air Quality*, the *Georgia Rules for Air Quality Control, Georgia Rules Chapter 391-3-1-.02(ttt)* require that any boiler installed later than January 1, 2007 operating to produce greater than 25 MW of electricity for sale apply Best Available Control Technology (BACT) for control of mercury emissions. Therefore, a BACT evaluation has been conducted for the main facility boiler for control of mercury emissions.

Exhibit A provides calculations of potential emissions for each PSD pollutant for all of the proposed emission units at Plant Washington. Table 3-1 below provides a facility wide emissions summary for the facility.

Table 3-1 Facilitywide Emissions Summary

	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	VOC	Pb	HF	H_2SO_4
	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)
Coal-fired Boiler	654	654	374	3272	1818	5453	124	0.61	10.91	182
Auxiliary Boiler	2.10	2.10	0.25	5.26	10.51	0.88	0.26	9.46E-04	9.79E-04	6.31E-03
Emergency Diesel Generator	0.26	0.26	7.55E-03	1.52	4.88	2.06	0.26	-	-	-
Emergency Firewater Pump	0.193	0.19	5.54E-03	0.18	2.71	0.58	0.22	-	-	-
Cooling Towers	16.28	7.51	3.29E-02	-	-	-	-	-	-	-
Crusher House Dust Collector	4.51	4.51	0.72	-	-	-	-	-	-	-
Tripper Decker	3.38	3.38	0.54	-	-	-	-	-	-	-
Limestone Preparation Building	0.94	0.94	0.25	-	-	-	-	-	-	-
Fly Ash Mechanical Exhausters	0.45	0.45	0.26	-	-	-	-	-	-	-
Fly Ash Silo	0.28	0.28	0.16	-	-	-	-	-	-	-
Bottom Ash Transfer Point to Bottom Ash Bin	2.78E-02	1.32E-02	1.99E-03	-	-	-	-	-	-	-
Bottom Ash Transfer Point from Bin to Truck	2.78E-02	1.32E-02	1.99E-03	-	-	-	-	-	-	-
Mercury Sorbent Silo	7.04E-02	7.04E-02	7.04E-02	-	-	-	-	-	-	-
SO_3 Sorbent Silo	7.04E-02	7.04E-02	7.04E-02	-	-	-	-	-	-	-
Pre-Treatment Soda Ash Silo	3.52E-02	3.52E-02	3.52E-02	-	-	-	-	-	-	-
Pre-Treatment Hydrated Lime Silo	3.52E-02	3.52E-02	9.50E-03	-	-	-	-	-	-	-
PRB Stackout	0.28	0.28	4.51E-02	-	-	-	-	-	-	-
Illinois No. 6 Stackout	0.28	0.28	4.51E-02	-	-	-	-	-	-	-
Limestone Stackout	0.28	0.28	7.60E-02	-	-	-	-	-	-	-
Solid Material Handling - Ash	1.73	0.33	0.18	-	-	-	-	-	-	-
Solid Material Handling - Gypsum	1.73	0.33	0.18							
Limestone Unloading	4.39E-03	2.08E-03	3.15E-04	-	-	-	-	-	-	-
Unloading Conveyor to Limestone Stackout	3.53E-02	1.67E-02	2.53E-03	-	-	-	-	-	-	-
Limestone Pile	2.89E-03	2.89E-03	4.11E-04	-	-	-	-	-	-	-
Rail Unloading	2.72E-02	1.29E-02	1.95E-03	-	-	-	-	-	-	-
Inactive PRB Coal Pile	8.21	2.05	1.81E-01	-	-	-	-	-	-	-
Inactive Illinois No. 6 Coal Pile	8.21	2.05	1.81E-01	-	-	-	-	-	-	-
Active PRB Coal Pile	1.76E-02	8.79E-03	1.32E-03	-	-	-	-	-	-	-
Transfer Point for Active PRB Coal Pile	0.11	5.17E-02	7.83E-03							
Active Illinois No. 6 Coal Pile	1.76E-02	8.79E-03	1.32E-03	-	-	-	-	-	-	-
Transfer Point for Active Illinois Basin Coal Pile	0.11	5.17E-02	7.83E-03							
Solid Material Handling Haul Road	0.55	0.55	8.19E-02	-	-	-	-	-	-	-
Project Totals	705	681	377	3,279	1,836	5,457	124	0.62	10.91	182
PSD Significance Level	25	15	15	40	40	100	40	0.6	3	7
Significant Emissions Increase (Yes or No)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

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3.2 New Source Performance Standard – Subpart Da Applicability

40 CFR 60.40, Subpart Da regulations apply to fossil fuel fired electric utility steam generating units for which construction, modification, or reconstruction commenced after September 18, 1978 and have a heat input capacity of greater than 250 MMBtu/hr. Also, an electric utility steam generating unit is defined in 40 CFR 60.41Da (Definitions) as "*…any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steamelectric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility*". Since the main facility boiler will have a maximum heat input capacity of greater than 8300 MMBtu/hr, and meets the definition of an electric utility steam generating unit, the main facility boiler will be subject to Subpart Da.

Subpart Da contains regulatory provisions involving emission limitations, monitoring, reporting, and recordkeeping requirements for the pollutants PM, SO_2, NO_X, Hg, and opacity. The following is a summary of the emission standards present in Subpart Da. Additional regulatory provisions in Subpart Da, regarding compliance, monitoring, performance testing, and reporting are not provided in this document. The PM emission standards, NO_X emission standards, and Hg emission standards apply at all times except during periods of startup, shutdown, or malfunction (40 CFR 60.48Da(c)). The emissions limitations applicable to the main boiler operations are given below.

Opacity – 40 CFR 60.42Da

(b) On and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility 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.

Particulate Matter – 40 CFR 60.42Da

(c) Except as provided in paragraph (d) of this section, 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, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 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.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. 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, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility for which construction, construction, or modification commenced after February 28, 2005, any gases that contain PM in excess of:

(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 an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel.

Sulfur Dioxide – 40 CFR 60.43Da

(i) 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, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2 in excess of either: (i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or (ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

Nitrogen Oxides (NO_X) – 40 CFR 60.44Da

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, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under § 60.48Da(k).

Mercury (Hg) – 40 CFR 60.45Da

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If any unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 66×10^{-6} lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

(ii) If any unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 97 x 10^{-6} lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.*, bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the Btu, MWh, or MJ) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source, you must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit and the total Btu, MWh, or MJ contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i\left(HH_i\right)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

ELb = Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged according to this paragraph.

ELi = Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh;

HHi = For each affected source, the Btu, MWh, or MJ contributed by the corresponding subcategory i (coal rank) burned during the compliance period; and

N = Number of subcategories (coal ranks) being averaged for an affected source.

3.3 New Source Performance Standard – Subpart Db Applicability

40 CFR 60.40 Subpart Db regulations apply to steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and have a heat input capacity of 29 MW, or 100 MMBtu/hr. Since the facility auxiliary boiler will have a maximum heat input capacity of 240 MMBtu/hr, it will be subject to Subpart Db.

Subpart Db contains regulatory provisions involving emission limitations, monitoring, reporting, and recordkeeping requirements for the pollutants PM, SO_2, NO_X, and opacity. However, since the auxiliary boiler will only combust distillate fuel that contains less than 0.3 percent sulfur by weight, the auxiliary boiler is not subject to the PM, SO_2, or opacity limits in Subpart Db, per 40 CFR 60.42b(k)(1), 60.43b(h)(5), and 71 FR 9868. However, the auxiliary boiler will be subject to the NO_X emission standards under Subpart Db. Additional regulatory provisions in Subpart Db, regarding compliance, monitoring, performance testing, and reporting are not provided in this document. The NO_X emission standards applicable to the facility auxiliary boiler are given below.

Nitrogen Oxides (NO_X) – 40 CFR 60.44Db

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO_2) in excess of the following emission limits: Natural gas and distillate oil with a low heat release rate – 0.10 lb/MMBtu; Natural gas and distillate oil with a high heat release rate – 0.20 lb/MMBtu.

3.4 New Source Performance Standard – Subpart Y Applicability

40 CFR 60.250 Subpart Y regulations apply to any of the following affected facilities in a coal preparation plant that processes more than 200 tons per day of coal and were constructed or modified 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.

The affected facility operations described above at Plant Washington will be subject to the 40 CFR 60.252 Subpart Y standards for Particulate Matter, which establish an opacity limit. The opacity limit will be verified through use of EPA Method 9 and the procedures established in 40 CFR 60.254 Subpart Y. The opacity limit applicable to facility operations under Subpart Y is given below.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart 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.

3.5 New Source Performance Standard – Subpart OOO Applicability

The emission standards listed in 40 CFR 60 Subpart OOO, which provide standards of performance for non-metallic mineral processing plants for applicable sources constructed, modified, or reconstructed after August 31, 1983, apply to the limestone handling and processing operations at Plant Washington. Plant Washington will comply with the monitoring, testing, reporting, and recordkeeping requirements of Subpart OOO.

3.6 New Source Performance Standard – Subpart HHHH Applicability

The Plant Washington main boiler will be subject to the Subpart HHHH requirements contained in the Clean Air Mercury Rule (CAMR) and discussed in 40 CFR 60 Subpart HHHH since the proposed facility is a new coal fired power plant. The provisions of the Clean Air Mercury Rule (CAMR) are further discussed in Section 3.10.

3.7 New Source Performance Standard – Subpart IIII Applicability

40 CFR Part 60, Subpart IIII establishes standards of performance for stationary compression ignition internal combustion engines. Applicable sources to Subpart IIII at Plant Washington will include the emergency generator (engine) and the fire pump. Applicable emission standards under Subpart IIII are related to the hp rating of the engine and the year the engine was manufactured. The facility will comply with the applicable Subpart IIII emission limits by purchasing an emergency generator (engine) and fire pump certified to the emissions standards of Subpart IIII.

3.8 New Source Performance Standard – Subpart Kb

40 CFR Part 60, Subpart Kb establishes 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. Subpart Kb applies to storage vessels containing volatile organic liquids (VOLs) with a capacity greater than or equal to 75 cubic meters (m^3), or approximately 19,800 gallons. One on-site storage vessel, the 350,000 gallon distillate fuel oil tank used for operation of the auxiliary boiler and main boiler startup operations, will have a storage capacity greater than 75 m^3. However, Subpart Kb does not apply to storage vessels with a capacity greater than 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa). Since the vapor pressure of distillate fuel oil is below 3.5 kPa, the tank is exempt from Subpart Kb.

3.9 National Emission Standards For Hazardous Air Pollutants – Subpart ZZZZ

40 CFR Part 63, Subpart ZZZZ establishes a Maximum Achievable Control Technology (MACT) standard for Stationary Reciprocating Internal Combustion Engines. Engines rated at less than 500 hp, such as the emergency fire water pump, are not subject to the Rule. Under Subpart ZZZZ, emergency internal combustion engines, such as the emergency diesel generator at the facility, are subject to the initial notification requirements of 40 CFR 63.6645(d).

3.10 National Emission Standards For Hazardous Air Pollutants – Subpart DDDDD

40 CFR Part 63, Subpart DDDDD, affected Industrial, Commercial, and Institutional Boilers and Process Heaters. However, Subpart DDDDD was rescinded. Therefore, a case-by-case MACT evaluation was conducted for the facility auxiliary boiler. Although rescinded, the facility auxiliary boiler will comply with the emissions limits previously established for CO in Subpart DDDDD. The emission limits established by Subpart DDDDD were 0.03 lb/MMBtu for PM, 0.0009 lb/MMBtu for HCl, and 400 ppm for CO. The established BACT emission limits for PM and CO will demonstrate compliance with the case-by-case MACT emission limits for PM and CO.

3.11 Clean Air Mercury Rule (CAMR)

On March 15, 2005, the EPA issued the first federal rule to permanently reduce and cap Hg emissions from coal fired power plants. This rule, known as the Clean Air Mercury Rule (CAMR), builds on EPA's Clean Air Interstate Rule (CAIR) to reduce mercury emissions from coal fired power plants from an estimated 48 tons/yr to 15 tons/yr, a reduction of nearly 70 percent. The CAMR establishes standards of performance for mercury, limiting emissions from new and existing coal fired power plants and creating a market based, cap and trade program that will reduce nationwide emissions of mercury form coal fired power plants in two phases. The first phase involves a 38 ton/yr mercury cap by 2010 as a co-benefit reduction through reduction of SO_2 and NO_X emissions under the requirements of the CAIR. In the second phase, due in 2018, coal fired power plants will be subject to a second cap, reducing emissions to 15 tons/yr upon full implementation. Power plants with coal fired units will be required to install and operate mercury specific CEMs.

The requirements of the CAMR have been incorporated into the Georgia Rules For Air Quality Control, Chapter 391-3-1-.02(14). Plant Washington will maintain compliance with the applicable requirements of the CAMR.

3.12 Acid Rain Program

The Title IV Acid Rain provisions, adopted as part of the 1990 Clean Air Act (CAA) Amendments, are primarily designed to control SO_2 and NO_X emissions from fossil fuel-fired combustion devices in the electricity generating industry. Along with emission limitations, there are requirements for monitoring, testing, recordkeeping, and reporting. A new facility must apply for an acid rain program permit at least 24 months before operations of the proposed unit begin. All requirements of the Acid Rain Program will be met by Plant Washington. The proper Acid Rain Permit Application forms will be submitted following submittal of this permit application.

3.13 New Source Review

Plant Washington will be located in Washington County, which is currently classified as an attainment area for all criteria pollutants. PSD section (40 CFR 51.166) of the NSR Regulations (40 CFR 51 Subpart I) requires states to implement a program to prevent deterioration of air quality beyond National Ambient Air Quality Standards (NAAQS) levels. The Georgia EPD has implemented such a program by adopting past federal regulations (namely 40CFR 52.21). Because Plant Washington would be considered a new major PSD source of emissions, the project must be evaluated to determine whether emission increases will exceed major modification levels. This evaluation is discussed in Section 3.1, and the supporting analyses for PSD are presented in Sections 4, 5, 7, and 8.

3.14 Fine Particulate Review Requirements ($PM_{2.5}$)

In 1997 NAAQS were set for fine particulate. Fine particles or "$PM_{2.5}$" can aggravate heart and lung diseases and have been associated with premature death and a variety of serious health problems including heart attacks, chronic bronchitis and asthma attacks. This standard was set in addition to the PM_{10} NAAQS that was already existing. On September 8, 2005, the Environmental Protection Agency (EPA) issued a proposed rule implementing the 1997 fine particle ($PM_{2.5}$) national ambient air quality standards. On March 29, 2007, EPA issued a final rule defining requirements for state plans to clean the air in 39 areas where particle pollution levels do not meet national air quality standards. This rule addressed only those areas that which are not in attainment with the standard and listed no additional requirements for those areas which are currently in attainment with the standard. Therefore in this application we have reviewed and addressed control of emissions of PM_{10} which also includes the subcategory of $PM_{2.5}$. By doing this it is expected that controls specified for PM_{10} will also address required controls of $PM_{2.5}$.

3.15 Georgia State Requirements

The Georgia Rules For Air Quality Control, Chapter 391-3-1, have promulgated rules for emission limitations regarding visible emissions, fuel burning equipment, fugitive dust, and mercury emissions from new electric generating units. Georgia Rule 391-3-1-.02(ttt) requires application of BACT to Hg emissions from new coal-fired electric generation units installed after January 1, 2007 and that generate greater than 25 MW of electricity for sale. Therefore, the main boiler at Plant Washington will be subject to the Georgia Rule 391-3-1-.02(ttt). Additional emission limitation requirements under the Georgia Rules for Air Quality Control are less stringent than the application of BACT, or other applicable requirements such as New Source Performance Standards (NSPS) to the emission units present at Plant Washington. Plant Washington, where applicable, shall maintain compliance with all Georgia State Requirements.

3.16 Compliance Assurance Monitoring (CAM) Plan

The Compliance Assurance Monitoring (CAM) Rule, established in 40 CFR Part 64, was established in order to provide reasonable assurance that facilities comply with emissions limitations by monitoring the operation and maintenance of their control devices. In order to be subject to CAM, the following criteria must be met:

1. An emission unit must be subject to an emission limit or standard for the pollutant of concern.

2. A control device is used to achieve compliance with the emission limit or standard.

3. The emission unit’s potential pre control emissions are greater than the applicable Title V Major Source threshold for the pollutant of concern.

The CAM rule is not applicable to emission unit pollutant emissions that are subject to New Source Performance Standards (NSPS) or National Emission Standards For Hazardous Air Pollutants (NESHAP) regulations, Acid Rain Program, or other emissions trading programs. For example, Nitrogen Oxides (NO_X) and Sulfur Dioxide (SO_2) emissions from the main facility boiler are subject to monitoring requirements under the Acid Rain Program. Therefore, the facility will be exempt from CAM for NO_X and SO_2 for the main boiler.

A CAM Plan will be developed for applicable facility units and submitted with the facility Title V Application.

4.0 BACT ANALYSIS

4.1 Introduction

Sources undergoing a PSD review must apply BACT to any new or modified emission unit that emits a PSD-triggered pollutant in an amount above significant impact levels. Federal PSD regulations define BACT as "an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act, emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant." No BACT determination may be less stringent than the applicable NSPS, NESHAP, or State Implementation Plan (SIP) limits.

On December 1, 1987, the USEPA Assistant Administrator for Air and Radiation issued a memorandum that implemented certain program initiatives designed to improve the effectiveness of the NSR programs in the confines of existing regulations and SIPs. Among these was the "top-down" method for determining BACT. The top-down process provides that available control technologies be ranked in descending order of control effectiveness. The first step of this process is to evaluate the most stringent or "top" alternative. This represents BACT, unless it can be demonstrated, and the permitting authority agrees, that technical considerations, energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in a particular case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on, until the most appropriate control strategy is selected for each source.

BACT is required for any emission unit that emits a PSD triggering pollutant. Table 3-1 identifies all PSD triggering pollutants as PM/PM_{10}, NO_X, CO, SO_2, VOCs, Pb, Fluorides, and H_2SO_4. In addition, a BACT analysis should also address opacity. A BACT analysis is required for any emission unit that emits any one of these pollutants. Table 4-1 summarizes the facility operations requiring a BACT analysis.

Table 4-1 Facility Operations at the Facility Requiring a BACT Review

The Washington Plant
- Supercritical Pulverized Coal Boiler - Auxiliary Boiler - Diesel Engine Generator and Fire Water Pump - Cooling Towers - Material Handling and Storage Facilities - Storage Tanks

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4.2 Key Steps in a Top-Down BACT Analysis

To develop the BACT analysis, the key steps outlined in the NSR US PSD Guidance Document (1990) were followed. These steps include:

Step 1 – Identify All Control Technologies

The primary objective of Step 1 is, for the emission unit in questions (i.e. PC boiler) identify all "available" control options. Available control options are defined in the 1990 Draft New Source Review Workshop Manual as "*those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives. The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative*."

A lower polluting process or practice is considered applicable if it has been demonstrated for a similar emission unit or application. An add-on control is considered applicable if it can properly function given the physical characteristics of the pollutant stream being controlled (i.e. gas stream temperature, pollutant concentration, etc.).

Potentially applicable control options were surveyed. These included control technologies that have been used in other source categories and countries. Control technologies identified by LAER determinations were also included as available control technologies.

Based on the guidelines provided in the USEPA Draft New Source Review Workshop Manual document, a comprehensive list of available control technologies was developed for this permit application.

A December 13, 2005 letter from Stephen Page, Director of USEPA's Office of Air Quality, Planning and Standards to E3 Consulting, LLC regarding BACT requirements for proposed coal-fired power plant projects stated "*As noted in prior EPA decisions and guidance, EPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. For example, we do not require applicants proposing to construct a coal-fired steam electric generator to consider building a natural gas-fired combustion turbine as part of a BACT analysis, even though the turbine may be inherently less polluting per unit product (in this case electricity).*"

An excerpt from the USEPA's Draft New Source Review Workshop Manual, page B.13, states the following; "*Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler. However, there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis.*"

Due to the above discussed documentation, alternative plant design strategies, such as Integrated Gasification Combined Cycle (IGCC) or Circulating Fluidized Bed (CFB) technologies, have not been evaluated as part of this BACT analysis.

Step 2 – Eliminate Technically Infeasible Options

The purpose of Step 2 is to evaluate the technical feasibility of the control technology options identified in Step 1. Control technologies that have been installed and operated successfully on the type of emission unit under review are considered demonstrated and technically feasible. Control technologies that are not applicable or not available are determined to be technically infeasible. For a technology that has not been demonstrated for a particular type of emission unit, the Draft New Source Review Workshop Manual provides the following guidance.

"*Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible*."

"A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review. An exception would be if the technology were proposed and permitted under the qualifications of an innovative control device consistent with the provisions of 40 CFR 52.21(v) or, where appropriate, the applicable SIP."

"*Commercial availability by itself, however, is not necessarily sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration.*"

> "*Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary*."

Step 3 – Rank Remaining Technically Feasible Control Options

The third step in the five step Top-Down BACT evaluation process involves ranking of the technically feasible control options determined in Step 2 from most effective to least effective in terms of emissions reduction potential. Step 3 also determines the energy, economic, and environmental impacts associated with the technically feasible control options, which are more fully evaluated in Step 4 of the process.

Ranking control options involves the selection of appropriate units of emissions for comparison between types of control technologies and emission units. For purposes of this BACT evaluation, the unit of measure for the emission rate for each pollutant from a combustion source was pounds per million British thermal units (lb/MMBtu) with the exception of Mercury. For Mercury, the unit of measure was lb/MW-hr, which is an output based limit. The establishment of output based limits for mercury is consistent with the NSPS Subpart Da emission limits established for Mercury. Achievable emission limits were determined for each of the control technology options based on engineering estimates, published literature, and testing data from existing sources. After establishing performance levels for the technically feasible control technologies, tables were developed to rank the various control technology alternatives by their demonstrated emissions reduction performance. Also, as indicated in the Draft New Source Review Workshop Manual regarding selection of the defined "top" control technology alternative;

> "*…an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top, and review for collateral environmental impacts*."

Step 4 – Evaluate Remaining Control Technologies

Step 4 of the five step Top-Down BACT evaluation process involves evaluating the suitability of the ranked control technology options under Step 3, based on energy, economic, and environmental impacts of utilization of the control technology. The following excerpt, taken from the Draft New Source Review Workshop Manual, explains the general evaluation process of Step 4.

> *"If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT."*

The energy impacts analysis determines whether the use of the control technology results in any significant or unusual energy penalties or benefits. The economic impacts analysis evaluates average and incremental cost effectiveness to determine if use of the control technology would result in a negative economic impact. The evaluation of environmental impacts considers the site specific environmental impacts of use of the control technology option, involving issues such as waste generation, water use and discharge, visibility impacts, emissions of additional pollutants, etc.

Step 5 – Selection of BACT

> The highest ranked and most effective control option not eliminated in Step 4 for energy, economic, or environmental impacts is selected and proposed as BACT for that pollutant and emission unit.

Table 4-2 summarizes the proposed BACT levels for all emission units subject to BACT. This table provides the overall conclusions of all the analyses that follow. In addition to proposing BACT emission limits for the emission units subject to BACT, Table 4-2 also includes a summary of the proposed compliance methods for demonstrating compliance with the applicable pollutants. To develop these analyses, MACTEC obtained information from the following databases and listings to identify emission limits and control technologies which apply to sources being proposed for the Project:

- The USEPA RACT/BACT/LAER Clearinghouse (RBLC)
- USEPA's New Source Review Technology Transfer Network website
- Federal and State New Source Review (NSR) permits, permit applications, and associated reports
- Discussions with control technology vendors
- Discussions with Georgia EPD and other State Air Quality Branch personnel
- National Coal-Fired Utility NSR Spreadsheet (November 2007)

Reviewing the information provided in these documents ensure that the latest appropriate control technology results of these reviews provide a comprehensive list of control technologies that are used in industry today.

Table 4-2 BACT Analysis Summary Table

Source	Pollutant	Control Technology	Emission Limit (lb/MMBtu)	Proposed Compliance Test Method
Supercritical Pulverized Coal (SCPC) Boiler	Particulate Matter (PM/PM_{10})	Fabric Filter Baghouse	Total PM_{10} – 0.018 lb/MMBtu (3-hr. average) Total PM (excluding SAM) – 0.018 lb/MMBtu NSPS Limit 0.015 lb/MMbtu Filterable PM	PM_{10} – USEPA Method 201A/202 with N_2 Purge or USEPA CTM-039/40 PM – USEPA Method 5B
	Nitrogen Oxides (NO_X)	LNB/OFA/SCR	0.05 lb/MMBtu – Annual Avg.	CEMS Monthly Avg.
	Carbon Monoxide (CO)	Combustion Controls	0.15 lb/MMBtu – 30 Day Avg. 0.30 lb/MMBtu – 1 hr. Avg.	CEMS Monthly Avg. USEPA Method 10
	Volatile Organic Compounds (VOC)	Combustion Controls	0.0034 lb/MMBtu – 3 hr. Avg.	USEPA Method 25A Minus USEPA Method 18 (Methane Removal)
	Sulfur Dioxide (SO_2)	Wet Flue Gas Desulfurization (WFGD)	0.09 lb/MMBtu – 12 Month Rolling Avg. 996 lb/hr – 3 hr. Avg.	CEMS Monthly Avg. USEPA Method 6C
	Lead (Pb)	Fabric Filter Baghouse	1.69×10^{-5} lb/MMBtu – 3 hr. Avg.	USEPA Method 29
	Fluorides (as HF)	Wet Flue Gas Desulfurization (WFGD)	3.0×10^{-4} lb/MMBtu – 3 hr. Avg.	USEPA Method 13A or USEPA Method 26
	Sulfuric Acid Mist (H_2SO_4)	Sorbent Injection and Wet Flue Gas Desulfurization (WFGD)	0.005 lb/MMBtu – 3 hr. Avg.	USEPA CTM-013 (Controlled Condensate Method 8A)
	Mercury (Hg)	Multi-Control: Sorbent Injection In Conjunction With SCR/FF/WFGD	15×10^{-6} lb/MWh-hr Annual Avg.	USEPA Method 29, 30A, or 30B, or Ontario Hydro Method (ASTM Method D6784-02) CEMS
Auxiliary Boiler	Particulate Matter (PM/PM_{10})	Combustion Controls	0.02 lb/MMBtu	Fuel Specification
	Nitrogen Oxides (NO_X)	Combustion Controls – LNB/FGR	0.1 lb/MMBtu	Engineering Controls
	Carbon Monoxide (CO)	Combustion Controls	0.04 lb/MMBtu	Engineering Controls
	Volatile Organic Compounds (VOC)	Combustion Controls	0.003 lb/MMBtu	Engineering Controls

Table 4-2 BACT Analysis Summary Table (Continued)

Source	Pollutant	Control Technology	Emission Limit (lb/MMBtu)	Proposed Compliance Test Method
Auxiliary Boiler	Sulfur Dioxide (SO_2)	Use of Low Sulfur Diesel	0.05 lb/MMbtu	Fuel Specification
	Sulfuric Acid Mist (H_2SO_4)	Use of Low Sulfur Diesel	6.0 x 10^{-5} lb/MMBtu	Fuel Specification
Diesel Engine Generator and Fire Water Pump	Particulate Matter (PM/PM_{10})	Use of Low Sulfur Diesel	See BACT Discussion Section 4.5	
	Nitrogen Oxides (NO_X)	Good Combustion Practices		
	Carbon Monoxide (CO)	Good Combustion Practices		
	Volatile Organic Compounds (VOC)	Good Combustion Practices		
	Sulfur Dioxide (SO_2)	Use of Low Sulfur Diesel		
	Sulfuric Acid Mist (H_2SO_4)	Use of Low Sulfur Diesel		
Cooling Towers	Particulate Matter (PM/PM_{10})	Drift Eliminators	0.0005 percent Drift Total Dissolved Solids (TDS) Limit 3300 mg/L	Vendor Data Quarterly TDS Testing
Material Handling and Storage Facilities	Particulate Matter (PM/PM_{10})	See BACT Discussion Section 4.7		
Fuel Storage Tanks	VOC	See BACT Discussion Section 4.8		
Opacity	Multi – Pollutant	See BACT Discussion Section 4.9		

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4.3 Supercritical Pulverized Coal (SCPC) Boiler

This section contains the BACT analysis for the planned 850 MW net SCPC unit planned for use at the facility. A summary of the BACT results for the SCPC boiler is found in Table 4-2 above.

4.3.1 BACT Demonstration for PM Emissions from the Supercritical Pulverized Coal Boiler

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 coal-fired boilers is a result of incombustible inert matter (ash) in the fuel and condensable substances such as acid gases. Sub-bituminous coals such as PRB coals are usually of lower heating value due to the higher moisture content present when compared to bituminous coals.

Step 1 – Identify All Control Technologies

Lower Emitting Process or Practice – Coal Selection

A potential pre-combustion control method for reduction of Particulate Matter (PM) emissions is the use of coals that contain a lower ash content. Combustion of a lower ash containing coal would lead to a lower content of incombustible matter in the coal fuel source, leading to less fly ash generation and thus lower PM emissions.

Lower Emitting Process or Practice – Coal Cleaning

Coal cleaning, also called coal benefaction, or coal washing, is a cleaning process in which mineral ash matter is removed from mined coal to produce a “cleaner” coal. Coal cleaning is generally performed in order to remove impurities in the coal to improve the heat content of the coal, thereby improving power plant capacity, reduce maintenance costs at power plants and extend plant life. Coal cleaning is also performed to reduce potential air pollutants, including reduction of PM emissions through reduction of the ash content of the coal.

Fabric Filter Baghouse

Fabric filters are used for PM control in a wide variety of industries, including use as PM control on PC fired boilers, and are capable of achieving control efficiencies of 99 percent or greater. According to the USEPA's fabric filter fact sheet (2003) "*flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are the most common type of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Bags may be 6 to 9 m (20 to 30 ft) long and 12.7 to 30.5 centimeters (cm) (5 to 12 inches) in diameter. Groups of bags are placed in isolable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter*."

Advantages of fabric filters can include the following:

1. Can provide high collection efficiencies on both coarse and fine (submicron) particulates.

2. Fabric filters are available in a large number of configurations and system designs, allowing for high flexibility in design.

3. Collected material is collected dry for subsequent processing or disposal.

Some disadvantages of fabric filters include:

1. Fabric filters can have relatively high maintenance requirements (filter bag replacement).

2. Concentrations of dusts in the collector can represent a fire or explosion hazard if a spark or flame is somehow introduced.

3. The units cannot be operated in high moisture gas streams; moisture can cause caking or plugging of the fabric filter.

Dry Electrostatic Precipitator (ESP)

Dry electrostatic precipitators (ESPs) are used in a wide variety of source categories for control of PM emissions, and are capable of achieving control efficiencies of 99 percent or greater. The following is an excerpt from the USEPA's dry ESP fact sheet (2003);

"*An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In dry ESPs, the collectors are knocked, or "rapped", by various mechanical means to dislodge the particulate, which slides downward into a hopper where they are collected. The hopper is evacuated periodically, as it becomes full. Dust is removed through a valve into a dust handling system, such as a pneumatic conveyor, and is then disposed of in an appropriate manner*."

Advantages of dry ESPs include the following:

1. Are capable of very high efficiencies, even for small particulate sizes.
2. Can be designed for a wide range of gas temperatures, and can handle high temperatures (up to 1300 degrees F).
3. Relatively large gas flow rates can be effectively handled.

Some disadvantages of dry ESPs include the following:

1. High capital costs and high maintenance items, such as the wire discharge electrodes.
2. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

3. Fly ash from the combustion of low sulfur coal typically has a high resistivity, and thus is difficult to collect.

Wet Electrostatic Precipitator (WESP)

A Wet Electrostatic Precipitator (WESP) is commonly used in situations where a dry ESP is not viable, such as when the material to be collected is wet, flammable, or has a high resistivity. WESPs are commonly used by the wood products and metallurgical industries, and can achieve PM control efficiencies of greater than 99 percent. The following is an excerpt from the USEPA's WESP fact sheet (2003).

"*An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. The collection hoppers used by dry ESPs are replaced with a drainage system. The wet effluent is collected, and often treated on-site*."

Advantages of WESPs include the following:

1. Are capable of very high efficiencies, even for low particulate sizes.

2. Relatively large gas flow rates can be effectively handled.

3. WESPs can collect sticky particles, mists, and highly resistive or explosive dusts due to the humid atmosphere from washing in the ESP.

4. Continuous or intermittent washing with a liquid eliminates the reentrainment of particles, which dry ESPs are subject to through the rapping process.

Some disadvantages of WESPs include the following:

1. High capital costs and high maintenance items, such as the wire discharge electrodes.

2. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

3. WESPs add the complexity of a wash system, and the fact that the resulting slurry must be handled more carefully than a dry product, and can require treatment.

4. WESPs are typically operated at gas stream temperatures less than 190 degrees F, and usually must be constructed of noncorrosive materials.

Electro-Catalytic Oxidation

Electro Catalytic Oxidation is a multi-pollutant technology developed by the Powerspan Corporation. Electro Catalytic Oxidation is capable of simultaneously controlling NO_X, SO_2, PM, Hg, and other trace elements in a three step process involving ash removal in a conventional dry ESP, passing the gas stream through a barrier discharge reactor to oxidize gaseous pollutants, and finally passing the gas stream through a WESP.

Venturi Scrubber

A venturi scrubber is a type of wet scrubber using a venturi device to increase the gas velocity in the unit. Increased velocity of the gas stream improves the gas liquid contact in the scrubber. A cyclonic separator or mist eliminator is typically used to collect the PM and excess liquid droplets.

Centrifugal Separator (Cyclone)

A cyclone is a particulate control device which uses centrifugal forces to separate PM from the flue gas stream. The use of cyclones, and multiple cyclone type devices (multiclones) or series cyclone devices, are being replaced over time by more efficient control devices such as fabric filter baghouses and ESPs. Cyclones are not as efficient at collecting small particles, and are most efficient at collecting larger coarse particles. This is due to the fact that the smaller particles have a lower mass to generate the centrifugal forces needed for collection. Pulverized coal boilers tend to produce a smaller fraction of coarse particles compared to other types of boilers.

Advanced Hybrid Particulate Collector

An Advanced Hybrid Particulate Collector (AHPC) is a new type of control device under development which combines the best features of electrostatic precipitators (ESPs) and fabric filter baghouses. The AHPC combines the technologies of an ESP and a fabric filter baghouse into one control device.

Agglomerator

There are varying types of particulate control devices termed “agglomerator”. One such type, the Indigo Agglomerator, was developed in Australia for reduction in visible emissions from coal-fired boilers. An agglomerator is essentially a modification of a standard ESP design. In the Indigo Agglomerator there are two sections, a bipolar charger followed by a mixing section. The bipolar charger has varying passages with positive or negative charging. A conventional ESP only has negative charging electrodes. Following the charging sections, the positive and negatively charged particles are brought together in a mixing chamber, where the particles are electrostatically attracted to each other. The agglomerated particles enter the precipitator, where they are more effectively removed due to their large size.

Side Stream Separator

Side stream separation would be a type of particulate matter emission control in which a cyclone type primary separator in conjunction with a fabric filter baghouse in side stream relation to the cyclone separator would be used to collection PM emissions.

Step 2 – Eliminate Technically Infeasible Options

Lower Emitting Process or Practice – Coal Selection

The type of coal used in a boiler can greatly affect the design of the boiler and associated air pollution control equipment. While use of a lower ash fuel (and corresponding higher heating value coal) could result in lower PM emissions, any lower ash fuel used could have a higher sulfur content, and lead to increased emissions of SO_2. Also, coals are not typically sorted per ash content. Therefore, coal selection is not a technically feasible option for control of PM emissions for the facility.

Lower Emitting Process or Practice – Coal Cleaning

Coal cleaning is considered effective for coals with a significant overburden. However, 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 non-combustible material. Also, PRB coals typically contain low ash levels. For these reasons, coal cleaning is typically not conducted for PRB coals. Illinois #6 coals do contain a higher ash content than PRB coals. However, if these coals were to be washed, the moisture content of the coal would be increased, and the heating value of the coal would be degraded. This would lead to an increase in the amount of coal burned, and a potential subsequent increase in secondary pollutant emissions (such as SO_2). Therefore, due to the minimal expected reduction in PM emissions, and detrimental impacts to emissions of other pollutants, coal cleaning is not a technically feasible option for the facility for reduction of PM emissions.

Fabric Filter Baghouse

A Fabric filter baghouse is a proven technology in the control of PM/PM_{10} emissions from PC fired boiler units. This technology has been demonstrated in similar applications to the current project and is considered technically feasible.

Dry Electrostatic Precipitator (ESP)

A dry ESP is a proven technology in the control of PM/PM_{10} emissions from PC fired boiler units. This technology has been demonstrated in similar applications to the current project and is considered technically feasible.

Wet Electrostatic Precipitator (WESP)

A WESP is a proven technology in the control of PM/PM_{10} emissions. This technology has been demonstrated in similar applications to the current project and is considered technically feasible.

Electro-Catalytic Oxidation

The USEPA New Source Review Workshop Manual states that “technologies in the pilot scale testing stages of development would not be considered available for BACT review”. Since Electro Catalytic Oxidation is still in the pilot stage of development, and not commercially demonstrated, it is not considered technically feasible for this project.

Venturi Scrubber

A Venturi scrubber device alone cannot meet the NSPS Subpart Da limit of 0.015 lb/MMBtu filterable particulate matter, which is the minimal acceptable level for BACT. Therefore, they are considered technically infeasible for this BACT analysis.

Centrifugal Separator (Cyclone)

A cyclone alone cannot meet the NSPS Subpart Da limit of 0.015 lb/MMBtu. Therefore, they are considered technically infeasible for this BACT analysis.

Advanced Hybrid Particulate Collector (AHPC)

An AHPC is a new type of control device under development which combines the best features of ESPs and fabric filter baghouses. AHPCs are not yet commercially available, and therefore not considered technically feasible for this project.

Agglomerator

Limited information is available regarding the effectiveness of agglomerator particulate control devices when compared to more standard devices such as ESPs and fabric filter baghouses, and the potential effects of the loss of co-benefit control from use of a fabric filter baghouse. For this reason, agglomerators are not considered technically feasible for this project.

Side Stream Separator

Side stream separation would be a type of particulate matter emission control in which a cyclone type primary separator in conjunction with a fabric filter baghouse in side stream relation to the cyclone separator would be used to collection PM emissions. Side stream separation is much better suited for sources of coarse particulate matter, and is therefore not considered technically feasible for this project.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. The technically feasible control technologies identified in Step 2 included fabric filter baghouses, dry ESP, and WESP. According to the USEPA fact sheets, the typical new equipment design efficiencies for all three technologies are between 99 percent and 99.9 percent.

Energy Impacts

This subsection discusses the energy impacts of the PM control options. The main energy impact which affects the remaining control options is the electrical energy required to operate the system. Fabric filter baghouses require minimal electrical energy when compared to electrostatic precipitators (ESPs), which require use of electric power to impart an electric charge to capture the PM. Based on data in an USEPA Air Pollution Training Institute publication on Electrostatic Precipitator Operation, the power required to operate either a dry or wet electrostatic precipitator can be around 1000 watts per 1000 acfm, with limited collection efficiency degradation at 705 watts per 1000 acfm. For the estimated air flow currently available for the site, this could lead to ESP power requirements from 2 to 3 MW. A secondary energy impact is the energy impact associated with the pressure drop of the systems. An increase in pressure drop increases the power required to operate the system. Fabric filters can experience higher pressure drops than those associated with ESPs.

Environmental Impacts

PM control devices remove the PM from the exhaust stream. An obvious environmental concern surrounds the disposal of the collected PM. Fabric filter baghouses and dry electrostatic precipitators both collect dry collected waste materials that would have to be disposed of in accordance with applicable State and Federal Regulations. With a fabric filter baghouse, an additional waste source would be the disposal over times of worn out filter bags. With a wet electrostatic precipitator, both the collected and dried waste products would have to be disposed of in accordance with State and Federal Regulations, and wastewaters generated from the process would have to be treated and handled in accordance with applicable regulations.

Economic Impacts

An obvious economic impact is the loss of saleable power through the high internal power requirements of use of an electrostatic precipitator. As stated above, potential power requirements for ESP units at the site could exceed 2-3 MW. Using a rough estimation of an average power demand of 1000 watts per home, the power required for operation of facility ESP units would be roughly equivalent to the amount of power needed to supply electricity to 3,000 homes. However, potential power requirements associated with a fabric filter baghouse can also be significant due to high pressure drops across system bag filters. Based on data provided by the USEPA in air emissions control cost guidance, and the USEPA's Coal Utility Environmental Cost Model (CUECost), the cost effectiveness of fabric filter controls is approximately $32/ton PM removed.

Step 4 – Evaluate Remaining Control Technologies

Fabric filter baghouses and ESPs both provide the maximum degree of emissions reduction of PM emissions from coal-fired units. Both controls are cost effective and do not have any significant collateral environmental impacts. WESPs have a slight disadvantage when compared to fabric filter baghouses and dry ESPs, in that they produce a wet waste product, which can lead to additional treatment and disposal costs than with dry systems. While both a fabric filter baghouse and an ESP can achieve the maximum amount of PM reduction available, fabric filter baghouses have additional benefits when sorbent injection is used, and may be more effective in the combined control of metallic (i.e. Pb, Hg) emissions. For these reasons, a fabric filter baghouse is chosen as the most effective and top control.

Energy Impacts

Although a fabric filter baghouse would require additional auxiliary power to overcome the pressure drop across the fabric filter bags, such energy requirements would not be enough to preclude use of a fabric filter baghouse.

Environmental Impacts

There are no major environmental issues that would preclude the use of a baghouse. Waste materials collected by the fabric filter baghouses will be disposed of in accordance with State and Federal regulations.

Economic Impacts

Economic impacts are not a concern for a fabric filter baghouse as discussed in Step 3.

Step 5 – Selection of BACT

A summary of recent PM BACT evaluations conducted for similar projects can be found in the following Table 4-3. This table lists the emission levels determined for each project. BACT for PM emissions is proposed as a fabric filter baghouse with a PM emission limit of 0.018 lb/MMBtu on a 3-hr average basis, excluding sulfuric acid mist (H_2SO_4), and a PM_{10} emission limit of 0.018 lb/MMBtu (total – filterable and condensable) on a 3-hr average basis utilizing Method 201A and 202 with a nitrogen purge, or using Conditional Test Method 39 (CTM-039)/Conditional Test Method 40 (CTM-040). The filterable PM limit would be 0.015 lb/MMBtu per NSPS Subpart Da. This level of control and emission limit has been proposed as BACT on recent similar projects. These values are comparable to the BACT emission limits recently demonstrated through stack testing by the Santee Cooper Cross Generating Station, Unit 3 in

South Carolina. Facilities with lower BACT emissions limits, such as the TS Power Plant, have not yet been demonstrated in practice.

Table 4-3 PM Emissions from Pulverized Coal Boilers Taken from the RBLC

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Capacity (MW)	Control Description	Emission Limit	
TS POWER PLANT	NV	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	595	FABRIC FILTER DUST COLLECTION	0.012	lb/MMBtu
WYGEN 2	WY	CT-3030	9/25/2002	BOILER, 500 MW PC	90	FABRIC FILTER	0.012	lb/MMBtu
WYGEN 3	WY	CT-4517	2/5/2007	PC BOILER	100	BAGHOUSE	0.012	lb/MMBtu
LONGLEAF	GA	4911-099-0030-P-	5/14/07	BOILER #1	600	BAGHOUSE	0.012	lb/MMBtu
LONGLEAF	GA	4911-099-0030-P-	5/14/07	BOILER #2	600	BAGHOUSE	0.012	lb/MMBtu
COMANCHE STATION	CO	04UNITPB1015	7/5/2005	PC BOILER - UNIT 3	750	BAGHOUSE	0.013	lb/MMBtu
INTERMOUNTAIN POWER STATION UNIT 3	UT	DAQE-AN0327010-04	10/15/04	PC BOILER	900	BAGHOUSE	0.013	lb/MMBtu
ELY ENERGY STATION	NV		2007	SUPERCRITICAL BOILER	2-750	FABRIC FILTER	0.013	lb/MMBtu
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	112	FABRIC FILTER	0.015	lb/MMBtu
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	390	FABRIC FILTERS	0.015	lb/MMBtu
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	390	FABRIC FILTERS	0.015	lb/MMBtu
HARDIN GENERATOR PROJECT	MT	3185-00	6/11/2002	BOILER, PULVERIZED COAL-FIRED	382	MULTICLONE USED IN CONJUNCTION WITH WET SCRUBBER	0.015	lb/MMBtu
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	7800 mmbtu	KCPL SHALL INSTALL A FABRIC FILTRATION SYSTEM (BAGHOUSE) FOR THE UNIT 2 BOILER TO REDUCE PM10 EMISSIONS.	0.015	lb/MMBtu
BIG CAJUN II POWER PLANT	LA	PSD-LA-677	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	675	ESP AND BAGHOUSE IN SERIES CONFIGURATION	0.015	lb/MMBtu
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AN	7/24/2006	PULVERIZED COAL BOILER	800	BAGHOUSE	0.015	lb/MMBtu
THOROUGHBRED GENERATING STATION	KY	TV-02-001	10/11/2002	BOILER, COAL, (2)	2-750	ESP, AND WET ELECTROSTATIC PRECIPATATOR (WESP)	0.018	lb/MMBtu
VIRGINIA TECH	VA	20124	9/15/2005	OPERATION OF BOILER 11	43	BAG HOUSE EQUIPED WITH CEM	0.018	lb/MMBtu
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	798	BAGHOUSE	0.018	lb/MMBtu
HOLCOMB UNIT #2	KS	0550087/C-3855	10/8/2002	BOILER, PULVERIZED COAL	660	DRY FABRIC FILTER	0.018	lb/MMBtu
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	MO	888	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	565	FABRIC FILTER SYSTEM	0.018	lb/MMBtu

Table 4 3 PM Emissions from Pulverized Coal Boilers Taken from the RBLC (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Capacity (MW)	Control Description	Emission Limit	
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	500	FABRIC FILTER BAGHOUSE (WHEN FIRING COAL) NATURAL GAS USE (W/O BAGHOUSE) LIMITED TO 500 MMBTU/HR	0.018	lb/MMBtu
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	695	DRY SOLID INJECTION W/ FABRIC FILTER AND WET SCRUBBER	0.018	lb/MMBtu
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	695	DRY SOLID INJECTION W/ FABRIC FILTER AND WET SCRUBBER	0.018	lb/MMBtu
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER		FABRIC FILTER BAGHOUSES	0.018	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER , UNIT 1 - SN-01	800	BAGHOUSE	0.018	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER - SN-01	800	BAGHOUSE	0.018	lb/MMBtu
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #3	600	BAGHOUSE	0.018	lb/MMBtu
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #4	600	BAGHOUSE	0.018	lb/MMBtu
AES BEAVER VALLEY, LLC	PA	PA-04-446C	11/21/2001	COAL FIRED BOILER	631	BAGHOUSE	0.02	lb/MMBtu
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	500	FABRIC FILTER BAGHOUSE (WHEN FIRING COAL). NATURAL GAS USE (W/O BAGHOUSE) IS LIMITED TO 500 MMBTU/HR.	0.02	lb/MMBtu
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	250	BAGHOUSE	0.02	lb/MMBtu
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, COAL FIRED, MAIN STACK	240	BAGHOUSE	0.02	lb/MMBtu
JK SPRUCE ELECTRIC GENERATING STATION	TX	PSD-TX 1037 & 70492	12/28/05	UNIT 2 BOILER	750	FABRIC FILTER	0.022	lb/MMBtu
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	850	BAGHOUSE	0.0244	lb/MMBtu
ARCHER DANIELS MIDLAND COMPANY	IL	97070097	12/24/1998	BOILER (9&10), FLUIDIZED BED	440	FABRIC FILTER. IF UNIT DEMONSTRATES 0.015 LB/MMBTU OR LESS, TESTING INTERVAL IS DOUBLED.	0.025	lb/MMBtu
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	7675 mmbtu	BAGHOUSE	0.025	lb/MMBtu
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	7675 mmbtu	BAGHOUSE	0.027	lb/MMBtu
COLSTRIP ENERGY LIMITED PARTNERSHIP	MT	2035-03	3/20/1998	ELECTRIC GENERATION, MATERIAL TRANSFER		BAGHOUSE	0.03	lb/MMBtu
COLSTRIP ENERGY LIMITED PARTNERSHIP	MT	2035-03	3/20/1998	ELECTRIC GENERATION, BOILER	147	BAGHOUSE	0.03	lb/MMBtu

Table 4 3 PM Emissions from Pulverized Coal Boilers Taken from the RBLC (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Capacity (MW)	Control Description	Emission Limit	
TOQUOP	NV	ap4911-1146		SCPC BOILER	750	BAGHOUSE	0.03	lb/MMBtu
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	112	GOOD COMBUSTION PRACTICES	0.041	lb/MMBtu
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-	10/13/2004	BOILER, COAL FIRED	166	ESP	0.05	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD	10/15/2003	BOILER UNIT 7, COAL, WAP7	6700 mmbtu	COMBUSTION CONTROL	0.085	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	6700 mmbtu	COMBUSTION CONTROL	0.086	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	6700 mmbtu	COMBUSTION CONTROL	0.086	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	6700 mmbtu	FIRING NAT GAS	0.087	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	7400 mmbtu	COMBUSTION CONTROL	0.088	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	7400 mmbtu	COMBUSTION CONTROL	0.089	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	7400 mmbtu	FIRING NAT GAS	0.089	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	7400 mmbtu	NONE INDICATED	0.097	lb/MMBtu
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COAL	189	SINGLE STAGE DUST COLLECTOR/ESP	0.1	lb/MMBtu
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	35	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.14	lb/MMBtu
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	35	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.15	lb/MMBtu
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	7675 mmbtu	BAGHOUSE	0.18	lb/MMBtu
DESERET GENERATION AND TRANSMISSION COMPANY	UT	DAQE-186-98	3/16/1998	COAL FIRED BOILER	500	FABRIC FILTER	0.286	lb/MMBtu

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4.3.2 BACT Demonstration for NO_x Emissions from the Supercritical Pulverized Coal Boiler

NO_X emissions are formed from combustion of coal and other fossil fuels, and are formed from the formation of thermal NO_X in the combustion zone, and from oxidation of the nitrogen present in the fuel source. Thermal NO_X is formed when elemental Nitrogen present in the air reacts with Oxygen (O_2) in the high temperature environment of the combustion zone. Factors which can affect NO_X formation in a coal-fired boiler include the combustion zone temperature, nitrogen content of the fuel, and quantity of excess air present

Step 1 – Identify All Control Technologies

Lower Emitting Processes or Practices – LNB

Low NO_X Burners (LNBs) incorporate mechanisms for reducing the peak flame temperature in the combustion zone of a combustion unit. This reduction in peak flame temperature results in lower NO_X emissions. Peak flame temperature is controlled by carefully regulating the distribution and mixing of the fuel and air in the combustion zone, and is most commonly reduced by separating combustion into multiple zones, or stages. LNB are widely used for the reduction of NO_X emissions.

Lower Emitting Processes or Practices – OFA

In the OFA process, combustion air is diverted from the burners to create a fuel rich zone in the lower portion of the combustion zone, or furnace. This process inhibits fuel bound nitrogen conversion to NO_X emissions on fossil fuel fired boilers. Peak flame temperatures can be reduced to limit thermal NO_X formation. A high momentum air stream intersects the burner flames in the upper combustion zone, or furnace, to complete combustion. OFA can be used in conjunction with LNB technology.

Lower Emitting Processes or Practices – Flue Gas Recirculation (FGR)

In FGR, emissions of NO_X can be reduced by recirculating a portion of the boiler flue gas into the main combustion chamber. This process reduces the peak combustion temperature and lowers the percentage of oxygen in the combustion air/flue gas mixture, thus reducing the formation of thermal NO_X caused by high flame and combustion zone temperatures.

Selective Catalytic Reduction (SCR)

SCR is a post-combustion control process which chemically reduces NO_X into molecular nitrogen and water vapor. SCR is capable of NO_X reduction efficiencies in the range of 70 percent to 90 percent. The following is a description of the SCR process as described in the USEPA's Selective Catalytic Reduction Fact Sheet (2003); "*A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NO_X within a specific temperature range and in the presence of the catalyst and oxygen. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs*."

Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) is a post combustion control process which controls NO_X emissions through chemical reduction via a reducing agent. Stand alone NO_X reduction levels for an SNCR can range from 30 percent to 50 percent, and when used in conjunction with LNB or other combustion controls can achieve NO_X emissions reductions of 65 percent to 75 percent. The following is a description of the SNCR process as described in the USEPA's SNCR Fact Sheet (2003); "*SNCR is based on the chemical reduction of the NO_X molecule into molecular nitrogen (N_2) and water vapor (H_2O). In the SNCR process, the combustion unit acts as the reactor chamber. The reagent is generally injected within the boiler superheater and reheater radiant and convective regions, where the combustion gas temperature is at the required temperature range. The injection system is designed to promote mixing of the reagent with the flue gas. The number and location of injection points is determined by the temperature profiles and flow patterns within the combustion unit. Both ammonia and urea are used as reagents*."

SCONOx

The SCONOx system is a relatively new catalytic reduction technology that is based on integration of catalytic oxidation and absorption technology. The system uses a coated catalyst to oxidize and reduce both CO and NO_X emissions. NO_X emission are oxidized to NO_2 and then adsorbed onto the catalyst. In the second step, a proprietary regenerative natural gas is passed through the catalyst periodically. The natural gas desorbs the NO_2 from the catalyst and reduces it to N_2. The system does not use ammonia as a reagent, but instead uses natural gas as the basis for a proprietary catalyst regeneration process.

Rotating Opposed Fire Air (ROFA)

ROFA utilizes a booster fan to supply high velocity air to improve mixing and lower the maximum temperature, reducing the formation of thermal NO_X. ROFA has only been installed as a retrofit technology on units using bituminous coals.

Gas Re-Burning

Various forms of gas re-burn technologies exist, including Advanced Gas Reburning (AGR), Fuel Lean Gas Reburning (FLGR), Natural Gas Reburning (NGR), and Amine Enhanced Gas Injection (AEGI). Gas re-burning systems typically utilize a second combustion zone following the primary combustion zone in the main boiler. The second combustion zone has a secondary fuel source, such as natural gas or coal.

Electro-Catalytic Oxidation

Electro Catalytic Oxidation is a multi-pollutant technology developed by the Powerspan Corporation. Electro Catalytic Oxidation is capable of simultaneously controlling NO_X, SO_2, PM, mercury, and other trace elements in a three step process involving ash removal in a conventional dry ESP, passing the gas stream through a barrier discharge reactor to oxidize gaseous pollutants, and finally passing the gas stream through a WESP.

Hybrid SNCR/Catalyst Systems

An emerging technology involves the use of an SNCR and SCR system in series. The hybrid technology utilizes an SNCR to reduce NO_X levels with a controlled amount of ammonia slip. The ammonia slip then functions as an ammonia source for the secondary SCR step that achieves additional NO_X reduction and minimizes total ammonia slip.

Pahlman Process

The Pahlman process is a multi-pollutant control technology that simultaneously controls SO_2, NO_X, and mercury (Hg) emissions. EnviroScrub Technologies Corporation is the developer of the Pahlman process, and limited information on the process is available. The process is located downstream of the particulate matter collection device and uses a spray dryer absorber where a proprietary scrubber material is used.

THERMALONOx

THERMALONOx is a technology developed by Thermal Energy International, Inc. that uses the reaction of elemental phosphorous, oxygen, and nitrogen monoxide to form NO_2. The NO_2 further combines such that it can be removed by a wet scrubber.

Oxygen Enhanced Combustion

Oxygen enhanced combustion is a technology that replaces a small fraction of the combustion air at the burner with oxygen. By generating higher flame temperatures, nitrogen compounds from the coal are released in a manner allowing air staging to be more effective in reducing NO_X emissions. While demonstration data from use of this technology appears promising, this technology is still in the pilot stages of development.

Step 2 – Eliminate Technically Infeasible Options

Lower Emitting Process or Practice –LNB

LNBs are a proven and demonstrated technology for the reduction of NO_X emissions from combustion processes. LNBs are considered standard equipment for modern boilers, and are therefore considered technically feasible for this project.

Lower Emitting Process or Practice – OFA

OFA is a demonstrated technology for the reduction of NO_X emissions from combustion processes, commonly used in conjunction with LNB. OFA is a common design incorporation into new boilers. For these reasons, use of OFA is considered technically feasible for this project.

Lower Emitting Process or Practice – Flue Gas Recirculation (FGR)

FGR is a demonstrated technology in the reduction of NO_X emissions on gas and oil-fired boilers. FGR has only been commercially applied for oil and natural gas fired boiler systems. Technical issues have thus far precluded use of FGR technology with coal-fired boilers. Therefore, FGR technology is not considered technically feasible for this project.

Selective Catalytic Reduction (SCR)

SCR is a proven and demonstrated technology for the reduction of NO_X emissions on PC fired boiler units. For this reason, the use of SCR is considered technically feasible for this project.

Selective Non-Catalytic Reduction (SNCR)

SNCR is no longer widely considered a stand alone control technology, primarily because the technology cannot achieve the NSPS Subpart Da NO_X emissions limit of 1.0 lb/MW-hr. Therefore, use of SNCR is considered technically infeasible for this project.

SCONOx

SCONOx technologies have been developed and are currently commercially available for natural gas fired turbines and units. It is not a demonstrated technology for use with coal-fired boilers. Since this technology is not commercially available or applicable for a coal-fired boiler, use of this technology is considered technically infeasible for this project.

Rotating Opposed Fire Air (ROFA)

ROFA utilizes a booster fan to supply high velocity air to improve mixing and lower the maximum temperature, reducing the formation of thermal NO_X. ROFA has only been installed as a retrofit technology on units using bituminous coals. As the technology has not yet been developed or evaluated for sub-bituminous coals, and the design coal blend for the facility is a 50/50 blend of bituminous Illinois #6 and PRB coals, use of ROFA is not considered technically feasible for this project.

Gas Re-Burning

Various forms of gas re-burn technologies exist, including Advanced Gas Reburning, Fuel Lean Gas Reburning, Natural Gas Reburning, and Amine Enhanced Gas Injection. Gas re-burning systems typically utilize a second combustion zone following the primary combustion zone in the main boiler. The second combustion zone has a secondary fuel source, such as natural gas or coal.

As stand alone technologies, none of the gas re-burning options can meet the emission limit of 1.0 lb/MW-hr established by the NSPS standard set in 40 CFRP Part 60.44 Da. Re-burning technologies could be combined with SCR, but the combination of these technologies has not been shown to reduce emissions below the levels obtainable by an SCR alone. Therefore, the use of re-burning technologies is not considered technically feasible for this project.

Electro-Catalytic Oxidation

Electro Catalytic Oxidation is a multi-pollutant technology developed by the Powerspan Corporation. Electro Catalytic Oxidation is capable of simultaneously controlling NO_X, SO_2, PM, mercury, and other trace elements in a three step process involving ash removal in a conventional dry ESP, passing the gas stream through a barrier discharge reactor to oxidize gaseous pollutants, and finally passing the gas stream through a WESP.

The USEPA New Source Review Workshop Manual states that “technologies in the pilot scale testing stages of development would not be considered available for BACT review”. Since Electro Catalytic Oxidation is still in the pilot stage of development, and not commercially available, it is not considered technically feasible for this project.

Hybrid SNCR/Catalyst Systems

An emerging technology involves the use of an SNCR and SCR system in series. The hybrid technology utilizes an SNCR to reduce NO_X levels with a controlled amount of ammonia slip. The ammonia slip then functions as an ammonia source for the secondary SCR step that achieves additional NO_X reduction and minimizes total ammonia slip.

The technology has not been well proven, and has achieved NO_X reductions equivalent to stand alone SCR technology. Due to the lack of emissions reduction when compared to stand alone SCR technology, and the unproven nature of the technology, hybrid SNCR catalyst systems are considered technically infeasible for this project.

Pahlman Process

The Pahlman process is a multi-pollutant control technology that simultaneously controls SO_2, NO_X, and mercury (Hg) emissions. EnviroScrub Technologies Corporation is the developer of the Pahlman process, and limited information on the process is available. The process is located downstream of the particulate matter collection device and uses a spray dryer absorber where a proprietary scrubber material is used. The technology is still in the pilot study state of development. The USEPA New Source Review Workshop Manual states that "technologies in the pilot scale testing stages of development would not be considered available for BACT review". Since the Pahlman process is still in the pilot stage of development, and not commercially available, it is not considered technically feasible for this project.

THERMALONOx

THERMALONOx was tested on a full scale unit (335 MW) which was funded by American Electric Power Industry in 2001. This test showed the technology failed to reduce NO_X emissions from the unit. Since the THERMALONOx process is not a demonstrated technology, it is not considered technically feasible for this project.

Oxygen Enhanced Combustion

While demonstration data from use of this technology appears promising, this technology is still in the pilot stages of development. Since the oxygen enhanced combustion process is still in the pilot stage of development, and not commercially available, it is not considered technically feasible for this project.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

Following elimination of the technically infeasible control options in Step 2, SCR is the only effective add-on control technology. For added control of NO_X emissions, SCR can be used in conjunction with LNB and OFA. Recent control effectiveness values, based on the RBLC database, range from 0.05 lb/MMBtu to 0.09 lb/MMBtu.

Energy Impacts

LNB and OFA are standard design incorporations into combustion units and do not create any significant energy impacts. Use of the SCR will require additional power to overcome the pressure drop loss across the system catalyst, and operation of the SCR equipment (i.e. ammonia distribution equipment).

Environmental Impacts

Properly designed combustion controls, such as LNB and OFA do not create adverse environmental impacts, since such control are designed to minimize the generation of pollutant emissions. Use of SCR technology will require the storage and use of ammonia, which can have significant environmental consequences if not handled properly. Storage and use of ammonia at the facility could trigger requirements of multiple different USEPA and OSHA related programs, including Risk Management Programs (RMP), Process Safety Management (PSM), and specialized safety and training programs.

SCR systems have added collateral benefits in the conversion of elemental mercury to an oxidized form, typically mercuric chloride ($HgCl_2$). Elemental mercury is difficult to collect and remove in pollution control equipment, but the oxidized form can be collected in a wet flue gas desulfurization (wet scrubber) system.

Economic Impacts

Based on data provided by the USEPA in air emissions control cost guidance, and the USEPA's Coal Utility Environmental Cost Model (CUECost), the cost effectiveness of an SCR system is approximately \$1,650/ton of NO_X removed.

Step 4 – Evaluate Remaining Control Technologies

Energy Impacts

The energy impacts discussed in Step 3 above are not significant enough to preclude the use of SCR in combination with LNB and OFA.

Environmental Impacts

The environmental impacts discussed in Step 3 above are not significant enough to preclude the use of SCR in combination with LNB and OFA.

Economic Impacts

While the capital costs and annualized operating costs of implementation of SCR technology at the site are significant, SCR technology represents the top tier of controls available for NO_X emissions reduction. The economic impacts are not significant enough to preclude the use of SCR in combination with LNB and OFA.

Step 5 – Selection of BACT

A summary of recent NO_X BACT evaluations conducted for similar projects can be found in Table 4-4. Utilization of an SCR system in conjunction with LNB and OFA can achieve the maximum amount of NO_X emissions reduction available, and is both technically feasible and demonstrated in PC fired boilers. Therefore, BACT for NO_X emissions is proposed as use of an SCR system in conjunction with LNB and OFA, with an emission limit of 0.05 lb/MMBtu on an annual basis (12-month rolling average). This 12-month rolling average will be computed using consecutive 30 day rolling monthly averages. This level of control and emission limit has been proposed as BACT on similar recent projects. A review of Continuous Emissions Monitoring (CEMS) data available through the EPA Clean Air Markets web site indicated that the average NO_X emission rate for 63 coal fired boilers was 0.083 lb/MMBtu. The lowest demonstrated BACT NO_X emissions limits in practice have been demonstrated by the Midamerican Energy Company with a NO_X emission limit of 0.07 lb/MMBtu on a 30 day rolling average. Facilities with emission limits comparable to the proposed project site would include the Hugo Generating Station with a NO_X emissions limit of 0.05 lb/MMBtu on a 12-month rolling average. However, the Hugo Generating Station has not yet been constructed or demonstrated.

Table 4-4 Listing of NO_x Emissions from Pulverized Coal Boilers Taken From the RBLC

Facility Name	Facility State	Permit Number	Capacity (MW)	Permit Date	Process Name	Control Description	Emission Limit		Avg Period
WYGEN 3	WY	CT-4517	381	2/5/2007	PC BOILER	SCR/LNB/OVERFIRE AIR	0.05	lb/MMBtu	30-day rolling average
HUGO GENERATING STA	OK	97-058-C M 2 PSD	750	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)	0.05	lb/MMBtu	12-month rolling average
JK SPRUCE ELECTRIC GENERATING STATION	TX	PSD-TX 1037 & 70492	750	12/28/05	UNIT 2 BOILER	SCR/LNB/OVERFIRE AIR	0.05	lb/MMBtu	Annual average
WPS - WESTON PLANT	WI	04-RV-248	500	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	LOW NOX BURNERS, GOOD COMBUSTION PRACTICES SELECTIVE CATALYTIC REDUCTION (SCR)	0.06	lb/MMBtu	12-month rolling average
TOQUOP	NV	ap4911-1146	750		SCPC BOILER	SCR/LNB/OVERFIRE AIR	0.06	lb/MMBtu	24-hour rolling average
ELY ENERGY STATION	NV		2-750	2007	SUPERCRITICAL BOILER	SCR/LNB/OVERFIRE AIR	0.06	lb/MMBtu	24-hour rolling average
TS POWER PLANT	NV	AP4911-1349	200	5/5/2005	200 MW PC COAL BOILER	SCR & LOW NOX BURNERS	0.067	lb/MMBtu	unknown
HUGO GENERATING STATION	OK	97-058-C M 2 PSD	750	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	lb/MMBtu	30-day rolling average
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJEC	MT	3182-00	390	7/21/2003	BOILER, PC NO. 1	LOW NOX BURNER, OVERFIRE AIR, AND SCR.	0.07	lb/MMBtu	unknown
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJEC	MT	3182-00	390	7/21/2003	BOILER, PC NO. 2	LOW NOX BURNER, OVERFIRE AIR, SCR	0.07	lb/MMBtu	unknown
WPS - WESTON PLANT	WI	04-RV-248	500	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	LOW NOX BURNERS, GOOD COMBUSTION PRACTICES SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	lb/MMBtu	30-day rolling average
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	7675 mmbtu	6/17/2003	CBEC 4 BOILER	LOW NOX BURNERS, OVERFIRE AIR, AND SELECTIVE CATALYTIC REDUCTION	0.07	lb/MMBtu	30-day rolling average
BIG CAJUN II POWER PLANT	LA	PSD-LA-677	675	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION	0.07	lb/MMBtu	Annual average
OPPD - NEBRASKA CITY STATION	NE	58343C01	660	3/9/2005	UNIT 2 BOILER	SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	lb/MMBtu	30-day rolling average
WYGEN 2	WY	CT-3030	90	9/25/2002	BOILER, 500 MW PC	LOW NOX BURNERS/SCR	0.07	lb/MMBtu	30-day rolling average
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	800		PULVERIZED CAOL BOILER	AT THIS POINT, THE FLUE GAS HAS BEEN COOLED TO THE APPROPRIATE TEMPERATURE FOR SCR, SO IT NEXT PASSES THROUGH THE SCR REACTOR, WHERE NOX IS REDUCED TO FORM NITROGEN.	0.07	lb/MMBtu	30-day rolling average
LONGLEAF	GA	4911-099-0030-P- 01-0	600	5/14/07	BOILER #1	SCR/LNB/OVERFIRE AIR	0.07	lb/MMBtu	30-day rolling average
LONGLEAF	GA	4911-099-0030-P- 01-0	600	5/14/07	BOILER #2	SCR/LNB/OVERFIRE AIR	0.07	lb/MMBtu	30-day rolling average

Table 4-4 Listing of NO_x Emissions from Pulverized Coal Boilers Taken From the RBLC (Continued)

Facility Name	Facility State	Permit Number	Capacity (MW)	Permit Date	Process Name	Control Description	Emission Limit		Avg Period
INTERMOUNTAIN POWER STATION UNIT 3	UT	DAQE-AN032701004	900	10/15/04	PC BOILER	SCR/LNB/OVERFIRE AIR	0.07	lb/MMBtu	unknown
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER	MO	122004-007	798	12/15/2004	PULVERIZED COAL FIRED BOILER	IT WAS DETERMINED THAT THE BACT FOR NOX FROM THE PULVERIZED COAL FIRED BOILER IS GOOD COMBUSTION PRACTICES ALONG WITH SCR HAVING A NOX EMISSION LIMIT OF 0.08 LB/MMBTU ON A 30-DAY ROOLING AVERAGE.	0.08	lb/MMBtu	30-day rolling average
THOROUGHBRED GENERATING STATION	KY	V-02-001	2-750	10/11/2002	BOILER, COAL, (2)	PROPER BOILER DESIGN, LOW NOX BURNERS, AND SCR	0.08	lb/MMBtu	30-day rolling average
HOLCOMB UNIT #2	KS	0550087/C-3855	660	10/8/2002	BOILER, PULVERIZED COAL	SCR, LOW NOX BURNERS, SEPARATED OVERFIRE AIR (SOFA)	0.08	lb/MMBtu	
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATI	MO	888	565	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	SELCTIVE CATALYTIC REDUCTION (SCR) & GOOD COMBUSTION PRACTICE. BASIS OF STANDARD EMISSION LIMIT - 30-DAY AVG. ALT LIMIT 24 H AVG.	0.08	lb/MMBtu	30-day rolling average
KANSAS CITY POWER & LIGHT COMPANY - IATAN STAT	MO	012006-019	850	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS ARE NOT BACT FOR NOX AND SOX	0.08	lb/MMBtu	30-day rolling average
MAIDSVILLE	WV	R14-0024	695	3/2/2004	BOILER, PC	LOW-NOX BURNERS IN SERIES WITH SCR	0.08	lb/MMBtu	24-hour rolling average
WHELAN ENERGY CENTER	NE	58048	648	3/30/2004	BOILER, UNIT 2 UTILITY	SELECTIVE CATALYTIC REDUCTION	0.08	lb/MMBtu	unkown
SANTEE COOPER CROSS	SC	0420-0030-CI	600	2/5/04	BOILER #3	SCR/LNB/OVERFIRE AIR	0.08	lb/MMBtu	365-day rolling average
SANTEE COOPER CROSS	SC	0420-0030-CI	600	2/5/04	BOILER #4	SCR/LNB/OVERFIRE AIR	0.08	lb/MMBtu	365-day rolling average
HARDIN GENERATOR PROJECT	MT	3185-00	382	6/11/2002	BOILER, PULVERIZED COAL-FIRED	SELECTIVE CATALYTIC REDUCTION	0.09	lb/MMBtu	unkown
JEA NORTHSIDE GENERATING STATION	FL	PSD-FL-265	810	7/14/1999	BOILER, COAL	SELECTIVE NON-CATALYTIC REDUCTION (SNCR) EMISSION	0.09	lb/MMBtu	unkown
PLUM POINT ENERGY	AR	1995-AOP-R0	800	8/20/2003	BOILER , UNIT 1 - SN-01	LOW NOX BURNERS	0.09	lb/MMBtu	unkown
PLUM POINT ENERGY	AR	1995-AOP-R0	800	8/20/2003	BOILER - SN-01	LOW NOX BURNERS	0.09	lb/MMBtu	unkown
KANSAS CITY POWER & LIGHT COMPANY - IATAN STAT	MO	012006-019	695	1/27/2006	PULVERIZED COAL BOILER - UNIT 1		0.10	lb/MMBtu	30-day rolling average
SEVIER POWER COMPANY	UT	DAQE-AN2529001-04	270	10/12/2004	LOW-NOX BURNERS WITH SNCR (SELECTIVE NON-CATALYTIC REDUCTION)	LOW NOX BURNERS WITH SNCR WITH AMMONIA INJECTION	0.10	lb/MMBtu	30-day rolling average
AES BEAVER VALLEY, LLC	PA	PA-04-446C	631	11/21/2001	COAL FIRED BOILER	SNCR	0.10	lb/MMBtu	unknown

Table 4-4 Listing of NO$_x$ Emissions from Pulverized Coal Boilers Taken From the RBLC (Continued)

Facility Name	Facility State	Permit Number	Capacity (MW)	Permit Date	Process Name	Control Description	Emission Limit		Avg Period
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATI	MO	888	565	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	SELCTIVE CATALYTIC REDUCTION (SCR) & GOOD COMBUSTION PRACTICE. BASIS OF STANDARD EMISSION LIMIT - 30-DAY AVG. ALT LIMIT 24 H AVG.	0.12	lb/MMBtu	24-hour rolling average
EDISON MISSION ENERGY	PA	32-0055C	6600 mmbtu	5/25/1999	BOILER, COAL, PULVERIZED BITUMINOUS, UNITS 1, 2 &3	SCR. SEE COMMENT ABOUT NOX EMISSION LIMITS IN FACILITY NOTES. REGULATORY BASIS IS STATE IMPLEMENTATION PLAN.	0.15	lb/MMBtu	unknown
TWO ELK GENERATION PARTNERS, LIMITED PARTNERS	WY	CT-1352	250	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	LOW NOX BURNERS WITH OVER FIRE AIR AND SELECTIVE CATALYTIC REDUCTION	0.15	lb/MMBtu	unknown
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FA	WY	CT-1324	240	10/10/1997	BOILER, PULVERIZED COAL FIRED POWER GENERATION UNI	LOW NOX BURNERS ITH OVERFIRE AIR AND SELECTIVE CATALYTIC REDUCTION	0.15	lb/MMBtu	unknown
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FA	WY	CT-1324	1160	10/10/1997	BOILER, COAL FIRED, MAIN STACK	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION.	0.16	lb/MMBtu	unknown
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FA	WY	CT-1324	352	10/10/1997	LIQUIDS FROM COAL PLANT (3 MODULES PER PLANT)	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION	0.17	lb/MMBtu	unknown
SANTEE COOPER CROSS	SC	0420-0030-CI	600	2/5/04	BOILER #3	SCR/LNB/OVERFIRE AIR	0.185	lb/MMBtu	30-day rolling average
SANTEE COOPER CROSS	SC	0420-0030-CI	600	2/5/04	BOILER #4	SCR/LNB/OVERFIRE AIR	0.185	lb/MMBtu	30-day rolling average
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	2398	7/24/2006	PULVERIZED COAL BOILER	AT THIS POINT, THE FLUE GAS HAS BEEN COOLED TO THE APPROPRIATE TEMPERATURE FOR SCR, SO IT NEXT PASSES THROUGH THE SCR REACTOR, WHERE NOX IS REDUCED TO FORM NITROGEN.	0.20	lb/MMBtu	1-hour average
KIMBERLY CLARK/CHESTER PLANT	PA	23-0014A	73	6/24/1998	BOILER, VERTICAL		0.2	lb/MMBtu	unknown
KIMBERLY CLARK/CHESTER PLANT	PA	23-0014A	58	6/24/1998	BOILER, VERTICAL		0.2	lb/MMBtu	unknown
VIRGINIA TECH	VA	20124	43	9/15/2005	OPERATION OF BOILER 11	EMISSIONS CONTROLLED BY A MASS-FEED STOKER CONFIGURATION WITH LOW EXCESS AIR/STAGED COMBUSTION	0.246	lb/MMBtu	30-day rolling average
SOUTHWESTERN PUBLIC SERVICE COMPANY-HARRING	TX	P017M1	1134	10/17/2006	UNIT 3 BOILER	LOW NOX BURNERS, SEPARATED OVERFIRE AIR WINDBOX, WITH ADDITIONAL YAW CONTROL OF THE BURNERS FOR ADDITIONAL NOX CONTROL	0.3	lb/MMBtu	30-day rolling average

Table 4-4 Listing of NO_x Emissions from Pulverized Coal Boilers Taken From the RBLC (Continued)

Facility Name	Facility State	Permit Number	Capacity (MW)	Permit Date	Process Name	Control Description	Emission Limit		Avg Period
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	6700 mmbtu	10/15/2003	BOILER UNIT 7, COAL, WAP7	NONE INDICATED	0.324	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	6700 mmbtu	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	NONE INDICATED	0.325	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	6700 mmbtu	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	EMISSIONS SHALL COMPLY WITH 30 TAC CHAPTER 17.	0.352	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	6700 mmbtu	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	NONE INDICATED	0.353	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	7400 mmbtu	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	NONE INDICATED	0.38	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	7400 mmbtu	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	NONE INDICATED	0.38	lb/MMBtu	unknown
THERMAL VENTURES	VA	30529	35	2/15/2002	BOILER, STEAM	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.4	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	7400 mmbtu	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	NONE INDICATED	0.40	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	7400 mmbtu	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	NONE INDICATED	0.40	lb/MMBtu	unknown
DESERET GENERATION AND TRANSMISSION COMPANY	UT	DAQE-186-98	500	3/16/1998	COAL FIRED BOILER	BOILER DESIGN	0.5	lb/MMBtu	Annual average
DESERET GENERATION AND TRANSMISSION COMPANY	UT	DAQE-186-98	500	3/16/1998	COAL FIRED BOILER	BOILER DESIGN	0.55	lb/MMBtu	30-day rolling average
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	189	8/14/2001	POWER BOILER #1 & #2, COAL	LOW NOX STAGED BURNERS, CMS FOR O2 NOX EMISSIONS	0.7	lb/MMBtu	unknown
AES BEAVER VALLEY PARTNERS, INC.	PA	040446B	161	6/1/1999	BOILER, PULVERIZED COAL FIRED	LNB/SOFA MODEL DRB-XCL, LOW NOX BURNER	0.7	lb/MMBtu	unknown

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4.3.3 BACT Demonstration for CO Emissions from the Supercritical Pulverized Coal Boiler

Carbon Monoxide (CO) is a by-product of the incomplete combustion of carbon in the fuel source, in this case coal. 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 a resultant increase in NO_X emissions. Therefore, an evaluation of the reduction of CO emissions needs to take into account the potential secondary impacts on NO_X emissions.

Step 1 – Identify All Control Technologies

<u>Combustion Controls</u>

The use of combustion controls for CO emissions would be a lower pollutant emitting process, through managing the combustion process to optimize the combustion process and reduce the generation of CO emissions. 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. CO formation will be limited through the 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 CO 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 CO emissions, it would likely increase the formation of thermal NO_X, and increase overall NO_X emissions.

<u>Add-On Controls</u>

No effective add-on controls currently exist for CO emissions from a boiler. Use of control technologies such as afterburners would use large quantities of natural gas and simply convert CO to CO_2. Use of afterburners, and other control devices such as catalytic oxidation or flares, have not been demonstrated in practice in PC boiler units. Any such control devices would lead to negative secondary environmental impacts, such as increased fuel usage and associated air emissions.

Step 2 – Eliminate Technically Infeasible Options

As discussed above, the use of add-on controls for control of CO emissions for the PC boiler units is not technically feasible. Use of add-on controls such as flares, afterburners, catalytic oxidation, and external thermal oxidation have not been demonstrated in practice for control of CO emissions from PC fired 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 PC fired boiler CO emissions controls, and therefore considered technically feasible under the BACT evaluation process.

Step 3 – Rank Remaining Technically Feasible Control Options

Combustion controls are the only feasible technology for control of CO emissions. Combustion controls are designed to optimize the emissions of CO (and consequently NO_X) from a PC fired boiler. Therefore, there are no energy or environmental impacts associated with the implementation of combustion controls. Since combustion controls are now a standard part of the design process of a PC fired boiler, there are no economic impacts associated with the implementation of combustion controls.

Step 4 – Evaluate Remaining Control Technologies

There are no energy, environmental, or economic impacts associated with the use of combustion controls which precludes the use of combustion controls as BACT for CO emissions for a PC fired boiler.

Step 5 – Selection of BACT

Table 4-5 shows the RBLC listings for CO emissions from Pulverized Coal boilers. BACT for CO emissions is chosen as the implementation of combustion controls and an emission limit of 0.15 lb/MMBtu on a 30-day average basis and 0.30 lb/MMBtu on a 1-hr average basis. Although BACT determinations for similar PC fired boilers have selected BACT with emission limits as low as 0.10 lb/MMBtu, control of NO_X emissions is determined to be the most environmentally “sensitive” factor, as those sources have selected higher NO_X emissions limits than those proposed as part of this application. Also, sources with emission limits as low as 0.10 lb/MMBtu have not yet been demonstrated in practice. The lowest demonstrated BACT emission limit in practice is by the Hardin Generator Project with an emission limit of 0.15 lb/MMBtu. The emission limits chosen for this BACT evaluation are comparable to those chosen for recent similar projects. Therefore, through implementation of more strict NO_X emission limits as evaluated as part of the overall BACT evaluation for the facility PC fired boiler unit, a higher CO emission limit is chosen.

Table 4-5 RBLC Listings for CO Emissions from Pulverized Coal-Fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	
DESERET GENERATION AND TRANSMISSION COMPANY	UT	DAQE-186-98	3/16/1998	COAL FIRED BOILER	COAL	500	NONE INDICATED	0.08	lb/MMBtu
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	COAL	750	PROPER BOILER DESIGN AND OPERATION	0.10	lb/MMBtu
TOQUOP ENERGY, LLC	NV	AP4911-1146	DRAFT	750 MW PC BOILER	COAL	750	COMBUSTION CONTROLS	0.10	lb/MMbtu
ELY ENERGY CENTER	NV	AP4911-2241	DRAFT	(2) 750 MW PC BOILERS	COAL	750	COMBUSTION CONTROLS	0.10	lb/MMbtu
DESERT ROCK	NM	DRAFT	7/1/2006	(2) 750 MW PC BOILERS	COAL	750	NONE INDICATED	0.10	lb/MMbtu
TRIMBLE COUNTY GENERATING STATION	KY	DRAFT	7/6/2005	PULVERIZED COAL BOILER	COAL	750	GOOD COMBUSTION PRACTICES	0.10	lb/MMbtu
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	GOOD COMBUSTION PRACTICES	0.11	lb/MMBtu
JEA NORTHSIDE GENERATING STATION	FL	PSD-FL-265	7/14/1999	BOILER, COAL	COAL	810	GOOD COMBUSTION PRACTICES.	0.13	lb/MMBtu
COMANCHE STATION	CO	04UNITPB1015	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	750	GOOD COMBUSTION PRACTICES	0.13	lb/MMbtu
BIG CAJUN II POWER PLANT	LA	PSD-LA-677	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	SUBBITUMINOUS COAL		OPTIMUM BURNER DESIGN AND GOOD COMBUSTION TECHNIQUES	0.135	lb/MMbtu
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	PULVERIZED COAL	7800 MMBtu/hr	NONE INDICATED	0.14	lb/MMBtu
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	COAL	112	COMBUSTION CONTROL	0.15	lb/MMBtu
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	COAL	390	NONE INDICATED	0.15	lb/MMBtu
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	COAL	390	NONE INDICATED	0.15	lb/MMBtu
HOLCOMB UNIT #2	KS	0550087/C-3855	10/8/2002	BOILER, PULVERIZED COAL	COAL	660	GOOD COMBUSTION PRACTICES	0.15	lb/MMBtu
HARDIN GENERATOR PROJECT	MT	3185-00	6/11/2002	BOILER, PULVERIZED COAL-FIRED	COAL	382	NONE INDICATED	0.15	lb/MMBtu
TS POWER PLANT	NV	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	595	GOOD COMBUSTION PRACTICES	0.15	lb/MMBtu
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	500	GOOD COMBUSTION PRACTICES; LOW NOX BURNERS	0.15	lb/MMBtu

Table 4-5 RBLC Listings for CO Emissions from Pulverized Coal-Fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	PULVERIZED COAL	250	NONE INDICATED	0.15	lb/MMBtu
WYGEN 3	WY	CT-4517	2/5/2007	PC BOILER	SUBBITUMINOUS COAL	381	GOOD COMBUSTION	0.15	lb/MMBtu
WHELAN ENERGY CENTER	NE	58048	3/30/2004	BOILER, UNIT 2 UTILITY	SUBBITUMINOUS COAL	648	GOOD COMBUSTION CONTROLS	0.15	lb/MMBtu
WYGEN 2	WY	CT-3030	9/25/2002	BOILER, 500 MW PC	SUBBITUMINOUS COAL	5145 MMBtu/hr	GOOD COMBUSTION CONTROL	0.15	lb/MMBtu
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	LIQUIDS FROM COAL PLANT (3 MODULES PER PLANT)	SUBBITUMINUS COAL	352	NONE INDICATED	0.15	lb/MMBtu
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, COAL FIRED, MAIN STACK	SUBBITUMINUS COAL	352	NONE INDICATED	0.15	lb/MMBtu
HUGO GENERATING STATION	OK	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	COAL	750	GOOD COMBUSTION CONTROL	0.15	lb/MMBtu
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, PULVERIZED COAL FIRED POWER GENERATION UNI	COAL	240	DUE TO THE LNB/OFA STRATEGY TO CONTROL NOX IT WOULD BE COUNTER PRODUCTIVE TO LIMIT CO.	0.15	lb/MMBtu
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	COAL	600	COMBUSTION CONTROLS - 30 DAY ROLLING AVG	0.15	lb/MMbtu
JK SPRUCE ELECTRIC GENERATING UNIT 2	TX	70492	1/19/2006	PULVERIZED COAL FIRED ELECTRIC STEAM BOILER	COAL	750	GOOD COMBUSTION PRACTICES	0.15	lb/MMbtu
INTERMOUNTAIN POWER GENERATING STATION UNIT #3	UT	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	COAL	950	COMBUSTION CONTROLS	0.15	lb/MMbtu
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	PRB COAL	7675 MMBtu/hr	COMBUSTION CONTROLS	0.154	lb/MMBtu
GASCOYNE GENERATING STATION	ND	PTC 05005	6/3/2005	BOILER	COAL	220	GOOD COMBUSTION PRACTICES	0.154	lb/MMbtu
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	COAL	7800 MMBtu/hr	GOOD COMBUSTION CONTROL PRATICE	0.16	lb/MMBtu
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	COAL	798	THE UTILIZATION OF GOOD COMBUSTION PRACTICES WITH A CO EMISSION LIMIT OF 0.16 LBS/MMBTU WAS DETERMINED TO BE BACT FOR CO FROM THE PULVERZIE COAL FIRED BOILER.	0.16	lb/MMBtu
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	MO	888	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	COAL	384 T/HR	GOOD COMBUSTION PRACTICES	0.16	lb/MMBtu
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER	SUBBITUMINOUS COAL	660	COMBUSTION CONTROLS	0.16	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER , UNIT 1 - SN-01	SUB-BITUMINOUS COAL	800	COMBUSTION CONTROLS	0.16	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER - SN-01	SUB-BITUMINOUS COAL	800	COMBUSTION CONTROLS	0.16	lb/MMBtu
SANDY CREEK ENERGY STATION	TX	DRAFT	3/1/2005	BOILER	COAL	800	COMBUSTION CONTROLS	0.16	lb/MMbtu
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER NO. 3 AND 4	COAL	660	GOOD COMBUSTION PRACTICES	0.16	lb/MMbtu
AES BEAVER VALLEY, LLC	PA	PA-04-446C	11/21/2001	COAL FIRED BOILER	COAL	631	GOOD COMBUSTION PRACTICES	0.20	lb/MMbtu

Table 4-5 RBLC Listings for CO Emissions from Pulverized Coal-Fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COAL	COAL	189	LESS THAN 0.041 LB/MMBTU FROM COAL	0.20	lb/MMBtu
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COMBINED FUEL	COMBINED FUEL	223	RESTRICTION ON INPUTS	0.20	lb/MMBtu
VIRGINIA TECH	VA	20124	9/15/2005	OPERATION OF BOILER 11	COAL	43	CEM	0.226	lb/MMBtu
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-01-4	10/13/2004	BOILER, COAL FIRED	COAL	166	STAGED COMBUSTION AND GOOD COMBUSTION PRACTICES	0.25	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	COMBUSTION CONTROL	0.282	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	6750 MMBtu/hr	COMBUSTION CONTROL	0.292	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	COAL	6700 MMBtu/hr	COMBUSTION CONTROL	0.294	lb/MMBtu
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	COAL	600	COMBUSTION CONTROLS - 1 HR AVG	0.30	lb/MMbtu
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED CAOL BOILER	COAL	800	NONE INDICATED	0.30	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	6750 MMBtu/hr	COMBUSTION CONTROL	0.302	lb/MMBtu
SEVIER POWER COMPANY	UT	DAQE-AN2529001-04	10/12/2004	COMBUSTION CONTROLS	WESTERN COAL	270	NONE INDICATED	0.32	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	COAL	6750 MMBtu/hr	COMBUSTION CONTROL	0.321	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	COAL	6700 MMBtu/hr	COMBUSTION CONTROL	0.33	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	COAL & NAT GAS	2168	COMBUSTION CONTROL	0.33	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	COAL & NAT GAS	6700 MMBtu/hr	COMBUSTION CONTROL	0.33	lb/MMBtu
INDEPENDENCE	AR	449-AOP-R0	3/10/1998	BOILER (2 EACH), COAL FIRED	SUB-BITUMINOUS COAL	8700 MMBtu/hr	GOOD COMBUSTION PRACTICE	0.37	lb/MMBtu
NEAL ENERGY CENTER SOUTH	IA	05-A-655-P	9/28/2005	UNIT 4 BOILER	COAL	399	GOOD COMBUSTION	0.42	lb/MMBtu
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	COAL	35	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.44	lb/MMBtu
GEORGE NEAL NORTH	IA	05-A-878-P	12/9/2005	NEAL 1 BOILER	COAL	399	GOOD COMBUSTION PRACTICES	1.26	lb/MMBtu
GEORGE NEAL NORTH	IA	07-A-951-P	9/5/2007	NEAL 2 BOILER	COAL	903	GOOD COMBUSTION PRACTICES	1.63	lb/MMBtu

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4.3.4 BACT Demonstration for VOC Emissions from the Supercritical Pulverized Coal Boiler

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 PC fired boilers.

Step 1 – Identify All Control Technologies

Combustion Controls

The use of combustion controls for VOC emissions would be a lower pollutant emitting process, through managing the combustion process to optimize the combustion process and reduce the generation of VOC emissions. 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 NO_X, and increase overall NO_X emissions.

Add-On Controls

No effective add-on controls currently exist for VOC emissions from a boiler. Use of afterburners, and other control devices such as catalytic oxidation or flares, have not been demonstrated in practice in PC boiler units. Any such control devices would lead to negative secondary environmental impacts such as higher NO_X emissions. The use of combustion controls is widely recognized as BACT for VOC emissions for PC fired boilers.

Step 2 – Eliminate Technically Infeasible Options

As discussed above, the use of add-on controls for control of VOC emissions for the PC boiler units is not technically feasible. Use of add-on controls such as flares, afterburners, catalytic oxidation, and thermal oxidation have not been demonstrated in practice for control of VOC emissions from PC fired 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 PC fired boiler VOC emissions controls, and therefore considered technically feasible under the BACT evaluation process.

Step 3 – Rank Remaining Technically Feasible Control Options

Combustion controls are the only feasible technology for control of VOC emissions. Combustion controls are designed to optimize the emissions of VOC (and consequently NO_X) from a PC fired boiler. Therefore, there are no energy or environmental impacts associated with the implementation of combustion controls. Since combustion controls are now a standard part of the design process of a PC fired boiler, there are no economic impacts associated with the implementation of combustion controls.

Step 4 – Evaluate Remaining Control Technologies

There are no energy, environmental, or economic impacts associated with the use of combustion controls which precludes the use of combustion controls as BACT for VOC emissions for a PC fired boiler.

Step 5 – Selection of BACT

Table 4-6 provides RBLC listings for VOC emissions from Pulverized Coal-fired Boilers. BACT for VOC emissions is chosen as the implementation of combustion controls and an emission limit of 0.0034 lb/MMBtu on a 3-hr average basis. Selection of this BACT emissions limit is comparable as for other similar PC fired boiler units. The Hardin Generator Project has demonstrated compliance with a VOC BACT emission limit of 0.0034 lb/MMbtu. Although BACT determinations for similar PC fired boilers have selected BACT with emission limits as low as 0.0024 lb/MMBtu, such as for the Santee Cooper Cross Generating Station, control of NO_X emissions is determined to be the most environmentally "sensitive" factor, as the Santee Cooper Cross Generation Station has much higher NO_X emissions limits (0.08 lb/MMbtu annual limit) than those proposed as part of this application. Therefore, through implementation of more strict NO_X emission limits as evaluated as part of the overall BACT evaluation for the facility PC fired boiler unit, a higher VOC emission limit is chosen.

Table 4-6 RBLC Listings for VOC Emissions from Pulverized Coal-Fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	Emission Limit Unit
VIRGINIA TECH	VA	20124	9/15/2005	OPERATION OF BOILER 11	COAL	43	GOOD COMBUSTION PRACTICE	0.002	lb/MMBtu
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	1670	GOOD COMBUSTION PRACTICE	0.0024	lb/MMBtu
JK SPRUCE ELECTRIC GENERATING UNIT 2	TX	70492	1/19/2006	PULVERIZED COAL FIRED ELECTRIC STEAM BOILER	COAL	750	GOOD COMBUSTION PRACTICES	0.0025	lb/MMbtu
INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	UT	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950	COMBUSTION CONTROL	0.0027	lb/MMBtu
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	COAL	390	NONE INDICATED	0.003	lb/MMBtu
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	COAL	390	NONE INDICATED	0.003	lb/MMBtu
TOQUOP ENERGY, LLC	NV	AP4911-1146	DRAFT	750 MW PC BOILER	COAL	750	COMBUSTION CONTROLS	0.003	lb/MMbtu
DESERT ROCK ENERGY FACILITY	NM	DRAFT	7/1/2006	(2) 750 MW SCPC BOILERS	COAL	750	GOOD COMBUSTION PRACTICES	0.003	lb/MMbtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	COMBUSTION CONTROL	0.0030	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	COAL	6700 MMBtu/hr	COMBUSTION CONTROL	0.0030	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	6750 MMBtu/hr	COMBUSTION CONTROL	0.0031	lb/MMBtu
TRIMBLE COUNTY GENERATING STATION	KY	DRAFT	7/6/2005	PULVERIZED COAL FIRED BOILER	COAL	750	GOOD COMBUSTION PRACTICES	0.0032	lb/MMbtu
HARDIN GENERATOR PROJECT	MT	3185-00	6/11/2002	BOILER, PULVERIZED COAL-FIRED	COAL	382	GOOD COMBUSTION PRACTICES, SOME CONTROL OFFERED BY WET SCRUBBER (REQUIRED FOR SO2 CONTROL)	0.0034	lb/MMBtu
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER	SUBBITUMINOUS COAL	660	COMBUSTION CONTROLS	0.0034	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	COAL	6750 MMBtu/hr	COMBUSTION CONTROL	0.0035	lb/MMBtu
HOLCOMB UNIT #2	KS	0550087/C-3855	10/8/2002	BOILER, PULVERIZED COAL	COAL	660	GOOD COMBUSTION PRACTICES	0.0035	lb/MMBtu
COMANCHE STATION	CO	04UNITPB1015	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	750	GOOD COMBUSTION PRACTICES	0.0035	lb/MMBtu
ELY ENERGY CENTER	NV	AP4911-2241	DRAFT	(2) 750 MW PC BOILERS	COAL	750	COMBUSTION CONTROLS	0.0035	lb/MMbtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	6750 MMBtu/hr	COMBUSTION CONTROL	0.0035	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	COAL & NAT GAS	6750 MMBtu/hr	COMBUSTION CONTROL	0.0035	lb/MMBtu
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	COAL	112	NONE INDICATED	0.0035	lb/MMBtu
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED CAOL BOILER	COAL	800	NONE INDICATED	0.0035	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	COAL	6700 MMBtu/hr	COMBUSTION CONTROL	0.0036	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	COAL & NAT GAS	6700 MMBtu/hr	COMBUSTION CONTROL	0.0036	lb/MMBtu
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	COAL	7800 MMBtu/hr	GOOD COMBUSTION CONTROL PRACTICE	0.0036	lb/MMBtu

Table 4-6 RBLC Listings for VOC Emissions from Pulverized Coal-Fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	Emission Limit Unit
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	MO	888	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	COAL	384 T/HR	GOOD COMBUSTION PRACTICES	0.0036	lb/MMBtu
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	500	GOOD COMBUSTION PRACTICES, LOW NOX BURNERS	0.0036	lb/MMBtu
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	PRB COAL	7675 MMBtu/hr	COMBUSTION CONTROLS	0.0036	lb/MMBtu
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	PULVERIZED COAL	7800 MMBtu/hr	NONE INDICATED	0.0036	lb/MMBtu
HUGO GENERATING STATION	OK	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	COAL	750	GOOD COMBUSTION CONTROLS	0.0036	lb/MMBtu
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	COAL	600	COMBUSTION CONTROLS	3.60E-03	lb/MMbtu
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	GOOD COMBUSTION PRACTICES	0.004	lb/MMBtu
LONGVIEW POWER MAIDSVILLE	WV	R14-0024	3/2/2004	PULVERIZED COAL FIRED BOILER	COAL	600	GOOD COMBUSTION PRACTICES	0.004	lb/MMbtu
JEA NORTHSIDE GENERATING STATION	FL	PSD-FL-265	7/14/1999	BOILER, COAL	COAL	810	GOOD COMBUSTION PRACTICES.	0.005	lb/MMBtu
KIMBERLY CLARK/CHESTER PLANT	PA	23-0014A	6/24/1998	BOILER, VERTICAL	COAL	73	NONE INDICATED	0.006	lb/MMBtu
KIMBERLY CLARK/CHESTER PLANT	PA	23-0014A	6/24/1998	BOILER, VERTICAL	COAL	58	NONE INDICATED	0.006	lb/MMBtu
AES BEAVER VALLEY, LLC	PA	PA-04-446C	11/21/2001	COAL FIRED BOILER	COAL	631	NONE INDICATED	0.0068	lb/MMBtu
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	COAL	750	PROPER BOILER DESIGN AND OPERATION	0.0072	lb/MMBtu
DESERET GENERATION AND TRANSMISSION COMPANY	UT	DAQE-186-98	3/16/1998	COAL FIRED BOILER	COAL	500	BAGHOUSE GOOD COBUSTION	0.0095	lb/MMBtu
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-01-4	10/13/2004	BOILER, COAL FIRED	COAL	166	STAGED COMBUSTION AND GOOD COMBUSTION PRACTICES.	0.01	lb/MMBtu
WYGEN 2	WY	CT-3030	9/25/2002	BOILER, 500 MW PC	SUBBITUMINOUS COAL	5145 MMBtu/hr	GOOD COMBUSTION CONTROL	0.01	lb/MMBtu
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	PULVERIZED COAL	250	NONE INDICATED	0.015	lb/MMBtu
BIG CAJUN II POWER PLANT	LA	PSD-LA-677	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	SUBBITUMINOUS COAL	675	OPTIMUM BURNER DESIGN AND GOOD COMBUSTION TECHNIQUES	0.015	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER , UNIT 1 - SN-01	SUB-BITUMINOUS COAL	800	COMBUSTION CONTROLS	0.02	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER - SN-01	SUB-BITUMINOUS COAL	800	COMBUSTION CONTROLS	0.02	lb/MMBtu
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	LIQUIDS FROM COAL PLANT (3 MODULES PER PLANT)	SUBBITUMINUS COAL	352	NONE INDICATED	0.05	lb/MMBtu
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, COAL FIRED, MAIN STACK	SUBBITUMINUS COAL	352	NONE INDICATED	0.05	lb/MMBtu
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, PULVERIZED COAL FIRED POWER GENERATION UNI	COAL	240	DUE TO LNB/OFA STRATEGY TO CONTROL NOX IT WOULD BECOUNTER PRODUCTIVE TO LIMIT VOC.	0.05	lb/MMBtu
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COAL	COAL	189	GOOD PROCESS CONTROLS	0.1550	lb/MMBtu
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	COAL	35	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.18	lb/MMBtu

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4.3.5 BACT Demonstration for SO_2 Emissions from the Supercritical Pulverized Coal Boiler

Emissions of Sulfur Dioxide (SO_2) are generated in fossil fuel sources from oxidation of sulfur present in the fuel source. Uncontrolled emissions of SO_2 are therefore significantly affected by the sulfur content of the fuel source.

Step 1 – Identify All Control Technologies

Lower Emitting Process or Practice – Coal Selection

Emissions of Sulfur Dioxide (SO_2) result from the oxidation of sulfur present in the coal during the combustion process. Therefore, coal source selection can have an impact on SO_2 emissions from a coal fired boiler.

Lower Emitting Process or Practice – Coal Cleaning

Coal cleaning is generally performed in order to remove impurities in the coal to improve the heat content of the coal, thereby improving power plant capacity, reduce maintenance costs at power plants and extend plant life. Coal cleaning is also performed to reduce the sulfur content in the coal, to reduce the SO_2 emissions which result from oxidation of the sulfur present in the coal during combustion.

Lower Emitting Process or Practice – Coal Refining

Coal refining is a mechanical and thermal process to remove moisture, sulfur, nitrogen, and heavy metals from coal. Also, as a result of the refining process, the ash content and moisture of the coal can be lowered, as well as increasing the heat content of the coal. Coal refining processes include processes still in the research and development stage, such as patented technologies for conversion of coal to char, a “clean” boiler fuel, and processes already in limited operation such as the Evergreen Energy, Inc. K-Fuel patented pre-combustion coal refining process.

Wet Scrubber

Wet scrubbers systems are often used as FGD systems, where they are used to control emissions of SO_2 from oil and coal combustion sources from industrial sources and electrical utilities. A wet scrubber brings the exhaust gas stream into contact with a sorbent material designed to absorb and react with the SO_2 present in the gas stream. Reagents commonly used in the process include lime and limestone. Additives, such as magnesium, are sometimes added to the reagent materials to further improve the reaction of the reagent with the SO_2 present in the gas stream. However, magnesium enhancement has been found to be not well suited for larger scale electric utility units. The by-products of the wet scrubber are in a wet slurry form and must be dewatered prior to handling and further disposal. Wastewaters generated through the wet scrubbing process may also require some level of treatment.

Spray Dryer Absorber (Dry Scrubber)

In a spray dryer absorber (SDA), or spray dryer, a fine spray of reagent slurry (mixed with water) is atomized and comes into contact with the hot exhaust gas, or flue gas. Lime is the typical reagent used in an SDA unit. A significant part of the acidic components of the flue gas are rapidly absorbed into the alkaline droplets, with the water/moisture content present being evaporated simultaneously. Control of exhaust gas distribution, slurry flow rate, and spray droplet size ensure that the droplets introduced into the gas stream are effectively dried to a fine powder before touching the chamber walls of the spray dryer unit or exiting the spray dryer system. A portion of the reacted product is collected and discharged from the spray dryer absorber. The treated flue gas is then discharged to a fabric filter baghouse, or other PM control device, where additional reacted product is collected from the exhaust gas stream.

Circulating Dry Scrubber

A CDS is similar in concept and reaction chemistry to a spray dryer absorber (SDA). In a CDS system, a circulating fluidized bed arrangement is used for contacting the sorbent reagent, lime, with the SO_2 laden flue exhaust gas. As with a spray dryer absorber, the reaction products exit the system in a dry form and are collected down stream in a fabric filter baghouse or other PM control device.

Activated Carbon Flue Gas Desulfurization

In this system, activated carbon is used as the sorbent for removal of SO_2 emissions. Activated carbon is injected into the flue gas exhaust stream through a series of header nozzles upstream of a fabric filter baghouse or other PM control device. A portion of the reacted carbon and fly ash collected by the PM control device is recycled and injected back into the flue gas exhaust stream to minimize the need for fresh activated carbon, making the process a partially "regenerable" process.

Duct Sorbent Injection (DSI) and Wet Scrubber

One potential control technology is the combination of sorbent injection with a wet scrubber. A reagent, such as lime or limestone, is injected into the ductwork between the air heater and the PM control device. Sorbent injection technology could be used in conjunction with a wet scrubber device.

Duct Sorbent Injection (DSI) and Dry Scrubber

One potential control technology is the combination of sorbent injection with a dry scrubber. A reagent, such as lime or limestone, is injected into the ductwork between the air heater and the PM control device. Sorbent injection technology could be used in conjunction with a dry scrubber device.

Step 2 – Eliminate Technically Infeasible Options

Lower Emitting Process or Practice – Coal Selection

Coal selection is a demonstrated method for minimizing the amount of sulfur available for SO_2 formation. Therefore, coal selection is determined to be technically feasible for this project.

Lower Emitting Process or Practice – Coal Cleaning

Coal washing involves removing the sulfur from the fuel before combusting it in a boiler. The majority of the sulfur in the coal is organic and is chemically bonded in the molecular structure of the coal itself. 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. However, the pyritic sulfur contents of PRB and Illinois #6 coals is low, with a pyritic sulfur content of approximately 0.05% for PRB coals and approximately 2.15% for Illinois #6 coals. Assuming coal washing could remove 40% of the pyritic sulfur content of the coal, less than 1% of the sulfur (and corresponding SO_2 emissions) of the use of Illinois #6 coals would be expected. Therefore, coal washing would be ineffective because there would be little sulfur content removed by the process. Also, were these coals to be washed the moisture content of the coal would be increased, and the heating value of the coal would be degraded. This would lead to an increase in the amount of coal burned, and a potential subsequent increase in pollutant emissions. Therefore, due to the minimal expected reduction in SO_2 emissions, and potential increase in emissions due to the consumption of more coal, coal cleaning is not a technically feasible option for the facility for reduction of SO_2 emissions.

Lower Emitting Process or Practice – Coal Refining

Coal refining is not yet a demonstrated technology for controlling SO_2 emissions for a large scale coal combustion facility. A company called Evergreen Energy, Inc. is the only vendor currently found to offer refined PRB coal. The refined fuel product is called K-Fuel, and claims made regarding the use of the fuel indicate that the use of K-Fuel can lead to lower emissions of SO_2, NO_X, and CO than standard PRB coal. However, the company is only operating one facility in Wyoming which has thus far seen limited production. The company hopes to produce over 50 million tpy of K-fuel in 5 years, through full operation at the existing facility and expansion of new facilities. However, wide scale production and use, and demonstration of the improved performance of the K-fuel have yet to be conducted.

Based on the current lack of sufficient supply of coal refining facilities, coal refining is not considered an available technology for SO_2 emissions reduction. Therefore, coal refining is determined to be technically infeasible for this project.

Wet Scrubber

Wet scrubbers have been demonstrated in wide scale use on coal-fired boilers and are available from a number of vendors. Wet scrubbers are therefore considered to be technically feasible.

Spray Dryer Absorber (Dry Scrubber)

Dry scrubbers have been demonstrated in wide scale use on coal-fired boilers and are available from a number of vendors. Dry scrubbers are therefore considered to be technically feasible.

Circulating Dry Scrubber

Circulating Dry Scrubbers have not yet been demonstrated on a coal-fired boiler of greater than 400 MW. The size and scale differences between the proposed utility boiler and the boilers on which this technology has been demonstrated would likely lead to the requirement for further design, research, and testing for assessing viability on such a large scale unit. Circulating fluidized bed systems, as with a circulating fluidized bed boiler, are not in use at the size and scale of the proposed utility boiler. Therefore, circulating dry scrubber systems are not considered available for this project and are considered technically infeasible for this analysis.

Activated Carbon Flue Gas Desulfurization

Although some level of SO_2 removal would be expected from use of injection of activated carbon into the flue gas exhaust stream, removal efficiencies when using this technology as a stand alone control methodology are not as effective as those of other stand alone control devices, such as wet or dry scrubbers. Research data has shown that concentrations of NO_X in the flue gas exhaust stream, specifically nitrogen monoxide (NO), can lead to inhibition of the catalytic effect of the porous carbon material, leading to deteriorated desulfurization performance. This deteriorated desulfurization performance can lead to the requirement for an increasing amount of activated carbon use, thereby increasing the treatment costs. Activated carbon desulfurization would not be expected to reach the required SO_2 emissions reduction necessary to achieve BACT as a stand alone technology. Therefore, for the above listed reasons, the use of activated carbon flue gas desulfurization for removal of SO_2 emissions is considered technically infeasible for this project.

DSI and Wet Scrubber

Sorbent injection technology could be used in conjunction with a wet scrubber device. However, the control efficiency of the wet scrubber would be affected and would likely decrease due to the lower inlet SO_2 concentrations. Also, there is no data available to indicate that there would be a substantial SO_2 emissions reduction benefit from use of duct sorbent injection along with a wet scrubber. Inclusion of duct sorbent injection with a wet scrubber would lead to increased capital and annualized operating costs, with no assurance of an improved system performance from use of a wet scrubber alone. For these reasons, use of duct sorbent injection in conjunction with a wet scrubber is considered technically infeasible for control of SO_2 emissions for this project.

Duct Sorbent Injection (DSI) and Dry Scrubber

Sorbent injection technology could be used in conjunction with a dry scrubber device. However, as with the wet scrubber, the control efficiency of the dry scrubber would be affected and would likely decrease due to the lower inlet SO_2 concentrations. Also, there is no data available to indicate that there would be a substantial SO_2 emissions reduction benefit from use of duct sorbent injection along with a dry scrubber. Inclusion of duct sorbent injection with a dry scrubber would lead to increased capital and annualized operating costs, with no assurance of an improved system performance from use of a dry scrubber alone. Also, a secondary concern for use of duct sorbent injection with a dry scrubber is the potential for interference of the duct sorbent material with the operation of the dry scrubber. A sorbent material present in the flue gas exhaust stream could potentially interfere with the ability of the spray dryer absorber (dry scrubber) to evaporate the moisture in the reagent slurry, thus impacting the effectiveness of the unit. For these reasons, use of duct sorbent injection in conjunction with a dry scrubber is considered technically infeasible for control of SO_2 emissions for this project.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

The feasible control technologies found during Step 2 of this analysis include wet scrubbers, and spray dryer absorbers (dry scrubbers). Reviews were conducted of technical publications, the USEPA RBLC, and vendor information to determine the control efficiencies of each of these identified technically feasible SO_2 reduction technologies. Based on data provided in the 2000 USEPA report "*Controlling SO_2 Emissions: A Review of Technologies*" dry scrubbers can have design efficiencies of 90 percent to 95 percent, while wet scrubbers can have a design efficiency of 90 percent to greater than 95 percent. According to discussions with equipment vendors, typical achieved SO_2 removal efficiencies for dry scrubbers would be in the 90 percent to 92 percent range, with an expected efficiency of 95 percent or greater for a wet scrubber. In addition, wet scrubbers 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.

Energy Impacts

Energy penalties are much more significant for a wet scrubber than for a dry scrubber. With wet scrubbers, greater energy requirements exist due to greater system pressure drops and larger energy requirements for ancillary equipment, such as water recycling pumps, and slurry dewatering pumps. Utilization of a wet scrubber can demand greater than 2% of the gross power generation of the facility, while dry scrubbers can demand typically around 1% of the gross power generation of the facility.

Environmental Impacts

Wet scrubbers have an added collateral environmental benefit over dry scrubbers in that they are more effective in the capture of secondary acid gases in the flue gas exhaust stream than a dry scrubber, including reactive mercury, hydrogen chloride, and fluorides. Water consumption is an important environmental impact when evaluating wet scrubbers and dry scrubbers, since wet scrubbers have a more significant water usage than dry scrubbers. However, dry scrubbers are not truly “dry”, as water is used in preparation of the reagent slurry which is atomized and injected into the exhaust gas stream.

Another significant environmental impact involves the generation of solid waste and wastewaters from wet scrubbers and dry scrubbers. Wastewater from a wet scrubber would require more specialized handling and treatment than a dry scrubber, since dry scrubber systems do not produce blowdown or a wastewater stream. Wet scrubbers can produce a solid waste stream (gypsum) which can be marketable depending on the quality of the gypsum produced, and the status of the current market. Dry scrubbers produce a solid waste stream with little to no commercial value that is traditionally disposed of in a solid waste facility.

Economic Impacts

Coal selection was determined to be technically feasible for this project. The process proposed for Plant Washington is a unique process utilizing a 50/50 blend of both PRB and Illinois #6 coals. Current cost estimates for PRB coals, including transportation, are $50.83/ton. Current cost estimates for Illinois #6 coals are $51.31 per ton. However, while Illinois #6 coal is slightly more expensive than PRB coal, what must be considered is the Higher Heating Value (HHV), or Btu/lb content of PRB and the proposed 50/50 blend.

The typical HHV for PRB coals is 8456 Btu/lb, while the typical HHV for the 50/50 blend of PRB and Illinois #6 is 9628 Btu/lb. Since the HHV for PRB coals is lower, more PRB coals would have to be consumed than coals consumed for the 50/50 blend. The coal usage rate for burning just PRB coal would be approximately 491 ton/hr, while the coal usage rate for the 50/50 blend is approximately 431 ton/hr at the facility.

Based on the current PRB and Illinois #6 cost rate, the annualized fuel cost for burning just PRB would be approximately $219 million, but burning the proposed 50/50 blend leads to annualized costs of approximately $192 million. Therefore, there would be an incremental cost of usage of PRB only at the facility of approximately $27 million.

Using the sulfur content of a typical PRB coal of 0.32%, and applying a control efficiency of 97.5%, gives an annualized emission of 691 ton/yr of SO_2. Using the typical sulfur content of the 50/50 blend of 1.72%, and applying a control efficiency of 97.5%, gives an annualized emission of 3,272 ton/yr of SO_2 emissions. This is an incremental SO_2 emissions increase of approximately 2,581 ton/yr.

Applying the incremental cost of $27 million to the incremental potential reduction in emissions of SO_2 of 2,581 ton/yr gives a cost effectiveness of approximately $10,460/ton. Therefore, switching to burning just the low sulfur coal (PRB) is not cost effective and determined to be infeasible

Based on data provided by the USEPA in air emissions control cost guidance, and the USEPA's Coal Utility Environmental Cost Model (CUECost), the cost effectiveness of a wet flue gas desulfurization system (wet scrubber) would be approximately $840/ton of SO_2 removed.

Step 4 – Evaluate Remaining Control Technologies

Wet scrubbing, or wet flue gas desulfurization, is evaluated as the top control option since wet scrubbers are demonstrated as more efficient in the removal of SO_2 emissions.

Energy Impacts

As discussed above, while wet scrubber systems at the facility would use approximately 2 percent of the gross power generation of the facility, dry scrubbing systems would use almost 1 percent of the gross power generation of the facility. This approximately 1 percent difference in gross power demand does not preclude the use of a wet scrubber system at the facility.

Environmental Impacts

Wet scrubbers have an added collateral environmental benefit over dry scrubbers in that they are more effective in the capture of secondary acid gases in the flue gas exhaust stream than a dry scrubber, including reactive mercury, hydrogen chloride, and fluorides. Water consumption for a wet scrubber system would be higher than the water consumption for a dry scrubber, due to the inherent design difference present between a wet scrubber and a dry scrubber. However, the additional water consumption necessary for operation of a wet scrubber does not preclude the use of a wet scrubber at the facility. The waste stream present from a wet scrubber (gypsum) is a potentially saleable product. Waste streams generated by a wet scrubber are inherently more saleable or recyclable than those waste streams generated by a dry scrubber.

Economic Impacts

Economic impacts would not preclude use of a wet scrubber control device for control of SO_2 emissions.

Step 5 – Selection of BACT

A summary of recent SO_2 BACT evaluations conducted for similar projects can be found in Table 4-7. From these listings it is apparent that utilization of a wet scrubber (wet flue gas desulfurization) can achieve the maximum amount of SO_2 emissions reduction available, and is both technically feasible and demonstrated in Pulverized Coal (PC) fired boilers. The selection of the BACT emission limits for this project is based on an assumption of 97.5 percent control of the uncontrolled SO_2 emissions. A review of comparable wet scrubbing applications from data available from USEPA's Clean Air Markets website of CEMs data for coal-fired boilers indicates that 97.5 percent reduction is the highest removal efficiency that can be expected on a consistent basis. Uncontrolled SO_2 emissions are based on the design sulfur content and Higher Heating Value (HHV – Btu/lb) of the typical average (correlated to SO_2 annual average) and worst case (correlated to SO_2 3-hr. average) 50/50 blend of PRB coal and Illinois #6 coal. Therefore, BACT for SO_2 emissions is proposed as use of a wet scrubber with an emission limit of 0.09 lb/MMBtu on an annual average basis and 996 lb/hr on a 3-hr average basis. The annual (12-month rolling) average will be computed using consecutive 30 day rolling monthly averages. This level of control and emission limit has been proposed as BACT on similar recent projects. The lowest annual average SO_2 BACT emission limit demonstrated in practice is 0.0976 lb/MMBtu by the Deseret Generation and Transmission facility. Facilities with lower proposed emission limits, such as the Hugo Generation Station, have not yet been constructed or demonstrated in practice.

Table 4-7 RBLC Listings for SO_2 Emissions from Pulverized Coal Fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	PROCESS NAME	Thruput (MW)	Control Description	Emission Limit		Avg Period
INTERMOUNTAIN POWER STATION UNIT 3	UT	DAQE-AN0327010-04	10/15/04	PC BOILER	900	WET LIMESTONE SCRUBBER	0.01	lb/MMBtu	unknown
ELY ENERGY STATION	NV		2007	SUPERCRITICAL BOILER	2-750	WET LIMESTONE SCRUBBER	0.06	lb/MMBtu	24-hour avg
TOQUOP	NV	ap4911-1146		SCPC BOILER	750	WET LIMESTONE SCRUBBER	0.06	lb/MMBtu	24-hour avg
HUGO GENERATING STATION	OK	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	750	WET LIMESTONE FLUE GAS DESULFURIZATION	0.065	lb/MMBtu	30-day rolling average
LONGLEAF	GA	4911-099-0030-P 01-0	5/14/07	BOILER #1	600	DRY SCRUBBER	0.065	lb/MMBtu	30-day rolling average
LONGLEAF	GA	4911-099-0030-P 01-0	5/14/07	BOILER #2	600	DRY SCRUBBER	0.12	lb/MMBtu	24-hr average
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	850	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS ARE NOT BACT FOR NOX AND SOX	0.09	lb/MMBtu	30-day rolling average
TS POWER PLANT	NV	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	595	LIME SPRAY SPRAY DRY SCRUBBER	0.09	lb/MMBtu	24-hour rolling
WYGEN 3	WY	CT-4517	2/5/2007	PC BOILER	381	DRY FGD	0.09	lb/MMBtu	12 month rolling
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	798	DRY FLUE GAS DESULFURIZATION > 90%	0.095	lb/MMBtu	30-day rolling average
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER		DRY FLUE GAS DESULFURIZATION & FABRIC FILTER	0.095	lb/MMBtu	30-day rolling average
DESERET GENERATION AND TRANSMISSION COMPANY	UT	DAQE-186-98	3/16/1998	COAL FIRED BOILER	500	WET SCRUBBER	0.0976	lb/MMBtu	12-month average
BIG CAJUN II POWER PLANT	LA	PSD-LA-677	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	675	OPTION 1: SEMI-DRY LIME SCRUBBER OPTION 2: WET FLUE GAS DESULFURIZATION SYSTEM	0.100	lb/MMBtu	Annual average
JK SPRUCE ELECTRIC GENERATING STATION	TX	PSD-TX 1037 & 70492	12/28/05	UNIT 2 BOILER	750	WET LIMESTONE SCRUBBER	0.1	lb/MMBtu	Annual average
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	850		0.100	lb/MMBtu	30-day rolling average
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	7675 mmbtu	LIME SPRAY DRYER FLUE GAS DESULFURIZATION	0.100	lb/MMBtu	30-day rolling average
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	500	DRY FGD, LIMIT ON EMISSIONS ENTERING CONTROL SYSTEM: 1.23 LBS/MMBTU 30 DAY AVG.	0.100	lb/MMBtu	30-day rolling average
WYGEN 2	WY	CT-3030	9/25/2002	BOILER, 500 MW PC	90	SEMI-DRY LIME SPRAY DRYER ABSORBER	0.100	lb/MMBtu	30-day rolling average
LAMAR LIGHT & POWER POWER PLANT	CO	05PR0027	2/3/2006	CIRCULATING FLUIDIZED BED BOILER	147	LIMESTONE INJECTION FOR S02 CONTROL . SAND IS USED AS INERT MATERIAL FOR REGULATION OF CIRCULATING BED TEMPERATURE	0.103	lb/MMBtu	daily average
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	112	LIMESTONE INJECTION	0.11	lb/MMBtu	

Table 4-7 RBLC Listings for SO_2 Emissions from Pulverized Coal Fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	PROCESS NAME	Thruput (MW)	Control Description	Emission Limit		Avg Period
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	390	DRY FLUE GAS DESULFURIZATION (FGD)	0.12	lb/MMBtu	24-hour average
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	390	DRY FLUE GAS DESULFURIZATION (FGD)	0.12	lb/MMBtu	24-hour average
HOLCOMB UNIT #2	KS	0550087/C-3855	10/8/2002	BOILER, PULVERIZED COAL	660	DRY FLUE GAS DESULFURIZATION	0.12	lb/MMBtu	
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	MO	888	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	565	DRY FLUE GAS DESULFURIZATION & LOW SULFUR COAL. EMISSION LIMIT BASIS - 30-DAY AVG.	0.12	lb/MMBtu	unknown
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	695	WET LIMESTONE FORCED OXIDATION	0.12	lb/MMBtu	30-day rolling average
SCHILLER STATION	NH	TP-B-0501	10/25/2004	BOILER, COAL FIRED, UNIT #5	186	LIME INJECTION, FUEL SULFUR LIMITS	0.12	lb/MMBtu	24-hour average
WHELAN ENERGY CENTER	NE	58048	3/30/2004	BOILER, UNIT 2 UTILITY	648	SPRAY DRYER ABSORBER (SDA)	0.12	lb/MMBtu	30-day rolling average
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #3	600	WET LIMESTONE SCRUBBER	0.13	lb/MMBtu	Annual average
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #4	600	WET LIMESTONE SCRUBBER	0.13	lb/MMBtu	Annual average
AES BEAVER VALLEY, LLC	PA	PA-04-446C	11/21/2001	COAL FIRED BOILER	631	HYDRATED ASH RE-INJECTION SYSTEM	0.14	lb/MMBtu	12-month rolling average
HARDIN GENERATOR PROJECT	MT	3185-00	6/11/2002	BOILER, PULVERIZED COAL-FIRED	382	WET VENTURI SCRUBBER	0.14	lb/MMBtu	30-day rolling average
	WV	R14-0024	3/2/2004	BOILER, PC	695	WET LIMESTONE FORCED OXIDATION	0.15	lb/MMBtu	24-hour average
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER , UNIT 1 - SN-01	800	DRY FLUE GAS DESULFURIZATION	0.16	lb/MMBtu	3-hour rolling average
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER - SN-01	800	DRY FLUE GAS DESULFURIZATION	0.16	lb/MMBtu	3-hour rolling average
VIRGINIA TECH	VA	20124	9/15/2005	OPERATION OF BOILER 11	43	DRY SCRUBBER FLUE GAS DESULFURIZATION SYSTEM AND CEMS	0.16	lb/MMBtu	30-day rolling average
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	2-750	WET FLUE GAS DESULFURIZATION (FGD), WESP, AND PROPER BOILER DESIGN	0.167	lb/MMBtu	30-day rolling average
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, COAL FIRED, MAIN STACK	240	LIME SPRAY DRYER	0.200	lb/MMBtu	2-hour fixed
JEA NORTHSIDE GENERATING STATION	FL	PSD-FL-265	7/14/1999	BOILER, COAL	810	PROPOSED CONTROLS: CIRC. FLUIDIZED BED SCRUBBER/ELECTROSTATIC PREC. OR SPRAY DRYER ABSORBER/FABRIC FILTER OR CIRC. FLUIDIZED BED SCRUBBER/FABRIC FILTER.	0.200	lb/MMBtu	24-hour average
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	250	LIME SPRAY DRY SCRUBBER	0.200	lb/MMBtu	2-hour fixed
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED COAL BOILER	800		0.30	lb/MMBtu	1-hour average
EDISON MISSION ENERGY	PA	32-0055C	5/25/1999	BOILER, COAL, PULVERIZED BITUMINOUS, UNIT 3	6600 mmbtu	WET LIMESTONE SCRUBBER	0.40	lb/MMBtu	

Table 4-7 RBLC Listings for SO_2 Emissions from Pulverized Coal Fired Boilers (Continued)

Facility Name	**Facility State**	**Permit Number**	**Permit Date**	**PROCESS NAME**	**Thruput (MW)**	**Control Description**	**Emission Limit**		**Avg Period**
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	35	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.47	lb/MMBtu	unknown
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #3	600	WET LIMESTONE SCRUBBER	0.6	lb/MMBtu	30-day rolling average
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #4	600	WET LIMESTONE SCRUBBER	0.6	lb/MMBtu	30-day rolling average
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	7400 mmbtu	FUEL S CONTENT LIMITED	1.06	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	7400 mmbtu	BURN LOW-S SUBBITUMINOUS COAL	1.07	lb/MMBtu	unknown
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COAL	189	SULFUR IN COAL NOT TO EXCEED 1.2% BY WEIGHT	1.20	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	6700 mmbtu	LIMITED FUEL S CONTENT	1.20	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	6700 mmbtu	FUEL S CONTENT LIMITED	1.20	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	7400 mmbtu	FUEL S CONTENT LIMITED	1.20	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	6700 mmbtu	BURN LOW-S SUBBITUMINOUS COAL	1.20	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	6700 mmbtu	BURN LOW-S SUBBITUMINOUS COAL	1.20	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	7400 mmbtu	NONE INDICATED	1.20	lb/MMBtu	unknown

Prepared by: PMH 1/10/08
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4.3.6 BACT Demonstration for Pb Emissions from the Supercritical Pulverized Coal Boiler

Emissions of 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.

Step 1 – Identify All Control Technologies

Lower Emitting Process or Practice – Coal Cleaning

Coal cleaning, also called coal beneficiation, or coal washing, is a cleaning process in which mineral ash matter is removed from mined coal to produce a "cleaner" coal. Coal cleaning is generally performed in order to remove impurities in the coal to improve the heat content of the coal, thereby improving power plant capacity, reduce maintenance costs at power plants and extend plant life. Coal cleaning is also performed to reduce potential air pollutants, including reduction of PM emissions through reduction of the ash content of the coal. Lead present in the coal could also potentially be removed by coal cleaning.

Fabric Filter Baghouse

Fabric filters are used for PM control in a wide variety of industries, including use as PM control on PC fired boilers, and are capable of achieving control efficiencies of 99 percent or greater. According to the USEPA's fabric filter fact sheet (2003) "*flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are the most common type of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Bags may be 6 to 9 m (20 to 30 ft) long and 12.7 to 30.5 centimeters (cm) (5 to 12 inches) in diameter. Groups of bags are placed in isolable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.*"

Advantages of fabric filters can include the following:

1. Can provide high collection efficiencies on both coarse and fine (submicron) particulates.

2. Fabric filters are available in a large number of configurations and system designs, allowing for high flexibility in design.

3. Collected material is collected dry for subsequent processing or disposal.

Some disadvantages of fabric filters include:

1. Fabric filters can have relatively high maintenance requirements (filter bag replacement).

2. Concentrations of dusts in the collector can represent a fire or explosion hazard if a spark or flame is somehow introduced.

3. The units cannot be operated in high moisture gas streams; moisture can cause caking or plugging of the fabric filter.

Dry Electrostatic Precipitator (ESP)

Dry ESPs are used in a wide variety of source categories for control of PM emissions, and are capable of achieving control efficiencies of 99% or greater. The following is an excerpt from the USEPA's dry ESP fact sheet (2003);

"*An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In dry ESPs, the collectors are knocked, or "rapped", by various mechanical means to dislodge the particulate, which slides downward into a hopper where they are collected. The hopper is evacuated periodically, as it becomes full. Dust is removed through a valve into a dust handling system, such as a pneumatic conveyor, and is then disposed of in an appropriate manner*."

Advantages of dry ESPs include the following:

1. Are capable of very high efficiencies, even for small particulate sizes.

2. Can be designed for a wide range of gas temperatures, and can handle high temperatures (up to 1300°F).

3. Relatively large gas flow rates can be effectively handled.

Some disadvantages of dry ESPs include the following:

1. High capital costs and high maintenance items, such as the wire discharge electrodes.

2. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

3. Fly ash from the combustion of low sulfur coal typically has a high resistivity, and thus is difficult to collect.

Wet Electrostatic Precipitator (WESP)

A WESP is commonly used in situations where a dry ESP is not viable, such as when the material to be collected is wet, flammable, or has a high resistivity. WESPs are commonly used by the wood products and metallurgical industries, and can achieve PM control efficiencies of greater than 99 percent. The following is an excerpt from the USEPA's WESP fact sheet (2003).

"*An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. The collection hoppers used by dry ESPs are replaced with a drainage system. The wet effluent is collected, and often treated on-site.*"

Advantages of WESPs include the following:

1. Are capable of very high efficiencies, even for low particulate sizes.

2. Relatively large gas flow rates can be effectively handled.

3. WESPs can collect stick particles, mists, and highly resistive or explosive dusts due to the humid atmosphere from washing in the ESP.

4. Continuous or intermittent washing with a liquid eliminates the reentrainment of particles, which dry ESPs are subject to through the rapping process.

Some disadvantages of WESPs include the following:

1. High capital costs and high maintenance items, such as the wire discharge electrodes.

2. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

3. Wet ESPs add the complexity of a wash system, and the fact that the resulting slurry must be handled more carefully than a dry product, and can require treatment.

4. Wet ESPs are typically operated at gas stream temperatures under 190^{o}F, and usually must be constructed of noncorrosive materials.

Wet Scrubber

Wet scrubbers have been applied to control PM emissions from utility, industrial, commercial, and institutional boilers fired with coal, oil, wood, and liquid waste. In wet scrubbers, the gas stream is contacted by liquid droplets generated by spray nozzles. Physical adsorption depends on the properties of the gas stream and liquid solvent, such as density and viscosity, as well as specific characteristics of the pollutant in the gas and the liquid stream.

Advantages of wet scrubbers include:

1. Provide cooling for hot gases in the exhaust stream.

2. Corrosive gases and dusts can be neutralized.

3. Can handle flammable and explosive dusts with minimal risk.

Disadvantages of wet scrubbers include:

1. The effluent liquid creates a waste sludge, and disposal/handling of this sludge can be costly.

2. Liquid wastes generated from the process can require treatment.

3. Potential for corrosive problems exists.

Step 2 – Eliminate Technically Infeasible Options

Lower Emitting Process or Practice – Coal Cleaning

Coal cleaning is considered effective for coals with a significant overburden. However, 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 non-combustible material. Also, PRB coals typically contain low ash levels. For these reasons, coal cleaning is typically not conducted for PRB coals. Illinois #6 coals do contain a higher ash content than PRB coals. However, were these coals to be washed the moisture content of the coal would be increased, and the heating value of the coal would be degraded. This would lead to an increase in the amount of coal burned, and a potential subsequent increase in secondary pollutant emissions (such as SO_2). The Pb content of PRB and Illinois #6 coals is expected to be small (8 ppm). Therefore, due to the minimal expected reduction in Pb emissions, and detrimental impacts to emissions of other pollutants, coal cleaning is not a technically feasible option for the facility for reduction of Pb emissions.

Fabric Filter Baghouse

A Fabric filter baghouse is a proven technology in the control of PM/PM_{10} emissions (and therefore Pb) from PC fired boiler units. This technology has been demonstrated in similar applications to the current project and is considered technically feasible.

Dry Electrostatic Precipitator (ESP)

A dry electrostatic precipitator (ESP) is a proven technology in the control of PM/PM_{10} emissions (and therefore Pb) from PC fired boiler units. This technology has been demonstrated in similar applications to the current project and is considered technically feasible.

Wet Electrostatic Precipitator (ESP)

A wet electrostatic precipitator (ESP) is a proven technology in the control of PM/PM_{10} emissions (and therefore Pb). This technology has been demonstrated in similar applications to the current project and is considered technically feasible.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. The technically feasible control technologies identified in Step 2 included fabric filter baghouses, dry ESP, and wet WESP. According to the USEPA fact sheets, the typical new equipment design efficiencies for all three (3) technologies are between 99 percent and 99.9 percent for PM. Lead (Pb) control efficiencies for all three controls are estimated at 99 percent.

Energy Impacts

This subsection discusses the energy impacts of the Particulate Matter (PM) control options. The main energy impact which affects the remaining control options is the electrical energy required to operate the system. Fabric filter baghouses require minimal electrical energy when compared to electrostatic precipitators (ESPs), which require use of electric power to impart an electric charge to capture the PM. Based on data in an USEPA Air Pollution Training Institute publication on Electrostatic Precipitator Operation, the power required to operate either a dry or wet electrostatic precipitator can be around 1000 watts per 1000 acfm, with limited collection efficiency degradation at 705 watts per 1000 acfm. For the estimated air flow currently available for the site, this could lead to ESP power requirements from 2 to 3 MW. A secondary energy impact is the energy impact associated with the pressure drop of the systems. An increase in pressure drop increases the power required to operate the system. Fabric filters can experience higher pressure drops than those associated with ESPs.

Environmental Impacts

Fabric filter baghouses and dry electrostatic precipitators both collect dry collected waste materials that would have to be disposed of in accordance with applicable State and Federal Regulations. With a fabric filter baghouse, an additional waste source would be the disposal over times of worn out filter bags. With a wet electrostatic precipitator, both the collected and dried waste products would have to be disposed of in accordance with State and Federal Regulations, and wastewaters generated from the process would have to be treated and handled in accordance with applicable regulations.

Economic Impacts

An obvious economic impact is the loss of saleable power through the high internal power requirements of use of an electrostatic precipitator. As stated above, potential power requirements for ESP units at the site could exceed 3 MW. Using a rough estimation of an average power demand of 1000 watts per home, the power required for operation of facility ESP units would be roughly equivalent to the amount of power needed to supply electricity to 3,000 homes. However, potential power requirements associated with a fabric filter baghouse can also be significant due to high pressure drops across system bag filters. The costing estimates for PM controls are discussed in Section 4.3.1 above.

Step 4 – Evaluate Remaining Control Technologies

Fabric filter baghouses and ESPs both provide the maximum degree of emissions reduction of PM emissions from coal-fired units, and are presumed to provide equally effective control for lead (Pb) emissions. Both controls are cost effective and do not have any significant collateral environmental impacts. Wet Electrostatic Precipitators have a slight disadvantage when compared to fabric filter baghouses and dry ESPs, in that they produce a wet waste product, which can lead to additional treatment and disposal costs than with dry systems. While both a fabric filter baghouse and an ESP can achieve the maximum amount of lead emissions reduction available, fabric filter baghouses have additional benefits when sorbent injection is used, and may be more effective in the combined control of additional metallic (i.e. Hg) emissions. For these reasons, a fabric filter baghouse is chosen as the most effective and top control.

Energy Impacts

Although a fabric filter baghouse would require additional auxiliary power to overcome the pressure drop across the fabric filter bags, such energy requirements would not be enough to preclude use of a fabric filter baghouse.

Environmental Impacts

There are no major environmental issues that would preclude the use of a baghouse. Waste materials collected by the fabric filter baghouses will be disposed of in accordance with State and Federal regulations.

Economic Impacts

Economic impacts are not a concern for a fabric filter baghouse as discussed in Step 3.

Step 5 – Selection of BACT

A summary of recent lead (Pb) BACT evaluations conducted for similar projects can be found in Table 4-8 below. BACT for lead (Pb) emissions is proposed as a fabric filter baghouse with an emission limit of 1.69×10^{-5} lb/MMBtu on a 3-hr average basis. This emission limit was recently demonstrated in practice by the Santee Cooper Cross Generating Station, Unit 3, in South Carolina and is the most stringent BACT emissions limit for lead achieved in practice. This level of control and emission limit has been proposed as BACT on recent similar projects.

Table 4-8 RBLC Listings for Pb Emissions from Pulverized Coal-Fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	Emission Limit Unit
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	660	ESP	1.69E-05	lb/MMBtu
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	DRY SOLID INJECTION W/ FABRIC FILTER AND WET SCRUBBER	1.78E-05	lb/MMBtu
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	COAL	600	FABRIC FILTER BAGHOUSE	1.80E-05	lb/MMbtu
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	50	FABRIC FILTER BAGHOUSE	2.51E-05	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER , UNIT 1 - SN-01	SUB-BITUMINOUS COAL	800	FABRIC FILTER	2.56E-05	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER - SN-01	SUB-BITUMINOUS COAL	800	FABRIC FILTER	2.56E-05	lb/MMBtu
ELY ENERGY CENTER	NV	AP4911-2241	DRAFT	(2) 750 MW PC BOILERS	COAL	750	FABRIC FILTER BAGHOUSE	2.59E-05	lb/MMbtu
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	COAL	798	NONE INDICATED	2.60E-05	lb/MMBtu
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	PRB COAL	7675 MMBtu/hr	BAGHOUSE	2.60E-05	lb/MMBtu
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	LIGNITE	2304	NONE INDICATED	3.31E-05	lb/MMBtu
TOQUOP ENERGY, LLC	NV	AP4911-1146	DRAFT	750 MW PC BOILER	COAL	750	FABRIC FILTER BAGHOUSE	4.00E-05	lb/MMbtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	5.52E-05	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	5.52E-05	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	COAL	6700 MMBtu/hr	NONE INDICATED	5.52E-05	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	COAL & NAT GAS	6700 MMBtu/hr	NONE INDICATED	5.52E-05	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	6750 MMBtu/hr	NONE INDICATED	5.81E-05	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	6750 MMBtu/hr	NONE INDICATED	5.81E-05	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	COAL & NAT GAS	6750 MMBtu/hr	NONE INDICATED	5.81E-05	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	COAL	6750 MMBtu/hr	NONE INDICATED	6.37E-05	lb/MMBtu
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED CAOL BOILER	COAL	800	NONE INDICATED	6.72E-05	lb/MMBtu

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4.3.7 BACT Demonstration for Fluoride Emissions from the Supercritical Pulverized Coal Boiler

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.

Step 1 – Identify All Control Technologies

Lower Emitting Process or Practice – Coal Cleaning

Coal cleaning, also called coal beneficiation, or coal washing, is a cleaning process in which mineral ash matter is removed from mined coal to produce a “cleaner” coal. Coal cleaning is generally performed in order to remove impurities in the coal to improve the heat content of the coal, thereby improving power plant capacity, reduce maintenance costs at power plants and extend plant life. Coal cleaning could reduce the levels of fluorine present in the coal, thereby reducing the amount of fluorine present and available to form HF during the combustion process.

Wet Scrubber

Wet scrubbers systems are often used as Flue Gas Desulfurization (FGD) systems, where they are used to control emissions of SO_2 from oil and coal combustion sources from industrial sources and electrical utilities. Wet scrubbers can also be used in the control of HF emissions. The HF is removed from the flue gas by sorption and reaction with the reagent slurry created by the wet scrubber. Reagents commonly used in the process include lime and limestone. Additives, such as magnesium, can be added to the reagent materials to further improve the reaction of the reagent with the HF present in the gas stream. The by-products of the wet scrubber are in a wet slurry form and must be dewatered prior to handling and further disposal. Wastewaters generated through the wet scrubbing process may also require some level of treatment.

Spray Dryer Absorber (SDA)

In a SDA, or spray dryer, a fine spray of reagent slurry is atomized and comes into contact with the hot exhaust gas, or flue gas. Lime is the typical reagent used in an SDA unit. A significant part of the acidic components of the flue gas, including HF, are rapidly absorbed into the alkaline droplets, with the water/moisture content present being evaporated simultaneously. Control of exhaust gas distribution, slurry flow rate, and spray droplet size ensure that the droplets introduced into the gas stream are effectively dried to a fine powder before touching the chamber walls of the spray dryer unit or exiting the spray dryer system. A portion of the reacted product is collected and discharged from the spray dryer absorber. The treated flue gas is then discharged to a fabric filter baghouse, or other PM control device, where additional reacted product is collected from the exhaust gas stream.

Circulating Dry Scrubber (CDS)

A CDS is similar in concept and reaction chemistry to a SDA. In a CDS system, a circulating fluidized bed arrangement is used for contacting the sorbent reagent, lime, with the HF present in the flue exhaust gas. A with a spray dryer absorber, the reaction products exit the system in a dry form and are collected down stream in a fabric filter baghouse or other PM)control device.

Sorbent Injection

One potential control technology is the use of sorbent injection, in which a reagent, such as limestone, is injected into the ductwork between the air heater and particulate collection device.

Step 2 – Eliminate Technically Infeasible Options

Lower Emitting Process or Practice – Coal Cleaning

As stated above in other pollutant evaluations, coal cleaning is not typically performed on the low sulfur PRB coals that will be used at the facility. There are no large scale coal cleaning facilities currently established for western coals such as PRB coals. Illinois #6 coals do contain a higher ash content than PRB coals. However, were these coals to be washed the moisture content of the coal would be increased, and the heating value of the coal would be degraded. This would lead to an increase in the amount of coal burned, and a potential subsequent increase in secondary pollutant emissions (such as SO_2). Therefore, due to the minimal expected reduction in HF emissions, and detrimental impacts to emissions of other pollutants, coal cleaning is not a technically feasible option for the facility for reduction of HF emissions.

Wet Scrubber

Wet scrubbers have been installed and operated on PC fired boiler units. Therefore, wet scrubbers are considered technically feasible for this project.

Spray Dryer Absorber (Dry Scrubber)

Dry scrubbers have been installed and operated successfully on PC fired boiler units. Therefore, dry scrubbers are considered technically feasible for this project.

Circulating Dry Scrubber

Circulating Dry Scrubbers have not yet been demonstrated on a coal-fired boiler of greater than 100 MW. The size and scale differences between the proposed utility boiler and the boilers on which this technology has been demonstrated would likely lead to the requirement for further design, research, and testing for assessing viability on such a large scale unit. Circulating fluidized bed systems, as with a circulating fluidized bed boiler, are not in use at the size and scale of this proposed utility boiler. Therefore, circulating dry scrubber systems are not considered available for this project and are considered technically infeasible for this analysis.

Sorbent Injection

Although there is limited evidence that sorbent injection would be effective at the removal of Hydrogen Fluoride (HF) emissions from the exhaust gas stream, sorbent injection is considered technically feasible for this analysis.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

The feasible control technologies found during Step 2 of this analysis include wet scrubbers, sorbent injection, and spray dryer absorbers (dry scrubbers). Reviews were conducted of technical publications, the USEPA RBLC, and vendor information to determine the control efficiencies of each of these identified technically feasible HF reduction technologies. There are not many instances where the performance of control technologies for HF emissions control has been evaluated and limited data exists as to the effectiveness of differing control technologies. A review of data on the RBLC database includes a variety of controls deemed applicable historically for BACT for HF emissions for coal fired boilers, including use of dry scrubbers, wet scrubbers, and sorbent injection with a fabric filter baghouse.

Energy Impacts

Energy penalties are much more significant for a wet scrubber than for a dry scrubber. With wet scrubbers, greater energy requirements exist due to greater system pressure drops and larger energy requirements for ancillary equipment, such as water recycling pumps, and slurry dewatering pumps. Utilization of a wet scrubber can demand greater than 2 percent of the gross power generation of the facility, while dry scrubbers can demand typically around 1 percent of the gross power generation of the facility. Utilization of sorbent injection along with a wet scrubber would be expected to add minimal power demand to the system. Any significant power demand for the sorbent injection system would come from power required to handle or process the sorbent powder or slurry.

Environmental Impacts

Wet scrubbers have an added collateral environmental benefit over dry scrubbers in that they are more effective in the capture of secondary acid gases in the flue gas exhaust stream than a dry scrubber, including reactive mercury, hydrogen chloride, and fluorides. Water consumption is an important environmental impact when evaluating wet scrubbers and dry scrubbers, since wet scrubbers have a more significant water usage than dry scrubbers. However, dry scrubbers are not truly “dry”, as water is used in preparation of the reagent slurry which is atomized and injected into the exhaust gas stream.

Another significant environmental impact involves the generation of solid waste and wastewaters from wet scrubbers and dry scrubbers. Wastewater from a wet scrubber would require more specialized handling and treatment than a dry scrubber, since dry scrubber systems do not produce blowdown or a wastewater stream. Sorbent injection would not be expected to produce a wastewater stream. Wet scrubbers can produce a solid waste stream (gypsum) which can be marketable depending on the quality of the gypsum produced, and the status of the current market. Dry scrubbers produce a solid waste stream with little to no commercial value that is traditionally disposed of in a solid waste facility.

Economic Impacts

The costing data for a wet scrubber is discussed in Section 4.3.5 above.

Step 4 – Evaluate Remaining Control Technologies

As stated above in Step 3, there are not many instances where the performance of control technologies for HF emissions control has been evaluated and limited data exists as to the effectiveness of differing control technologies. A review of data on the RBLC database includes a wide variety of controls deemed applicable historically for BACT for coal-fired boilers.

Therefore, for the above listed reasons, utilization of a wet scrubber is chosen as the top control option for control of HF emissions. Utilization of a baghouse system (for PM control) should provide some additional added control of HF emissions. Since the use of sorbent injection has been determined as BACT for control of H_2SO_4 emissions, there will be co-benefit control of HF emissions through use of the sorbent injection system.

Energy Impacts

While wet scrubber systems at the facility would use approximately 2 percent of the gross power generation of the facility, dry scrubbing systems would use almost 1 percent of the gross power generation of the facility. This approximately 1 percent difference in gross power demand does not preclude the use of a wet scrubber system at the facility. Utilization of sorbent injection along with a wet scrubber would be expected to add minimal power demand to the system. Any significant power demand for the sorbent injection system would come from power required to handle or process the sorbent powder or slurry.

Environmental Impacts

Wet scrubbers have an added collateral environmental benefit over dry scrubbers in that they are more effective in the capture of secondary acid gases in the flue gas exhaust stream than a dry scrubber, including reactive mercury, hydrogen chloride, and fluorides. Water consumption for a wet scrubber system would be higher than the water consumption for a dry scrubber, due to the inherent design difference present between a wet scrubber and a dry scrubber. However, the additional water consumption necessary for operation of a wet scrubber does not preclude the use of a wet scrubber at the facility. The waste stream present from a wet scrubber (gypsum) is a potentially saleable product. Waste streams generated by a wet scrubber are inherently more saleable or recyclable than those waste streams generated by a dry scrubber. Sorbent injection would not be expected to produce a wastewater stream. However, there would be additional solid wastes generated from use of the sorbent injection materials.

Economic Impacts

Economic concerns would not be an issue regarding use of a wet scrubber.

Step 5 – Selection of BACT

A summary of recent HF BACT evaluations conducted for similar projects can be found in Table 4-9 below. Utilization of a wet scrubber (wet flue gas desulfurization) is believed to achieve the maximum amount of HF emissions reduction available. Therefore, BACT for HF emissions is proposed as use of a wet scrubber and an emission limit of 0.0003 lb/MMBtu on a 3-hr average basis. This emission limit is the lowest BACT emission limit demonstrated in practice by the Santee Cooper Cross Generating Station, Unit 3, in South Carolina. Facilities with lower emission limits, such as the Thoroughbred Generation Station in Kentucky, have not yet been constructed or demonstrated in practice. This level of control and emission limit has been proposed as BACT on similar recent projects.

Table 4-9 RBLC Listings for Fluoride Emissions from Pulverized Coal-Fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	DRY SORBENT INJECTION W/ FABRIC FILTER BAGHOUSE	0.0001	lb/MMBtu
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	COAL	750	PROPER BOILER DESIGN AND CONTROL TECHNOLOGY, WFGD, AND WESP	0.000159	lb/MMBtu
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	PC BOILERS (2)	COAL	750	PROPER BOILER DESIGN AND CONTROL TECHNOLOGY, WFGD, AND WESP	0.000159	lb/MMBtu
WPS WESTON PLANT	WI	04-RV-248	10/19/2004	SUPERCRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER	COAL	500	DRY FGD AND BAGHOUSE	0.0002	lb/MMbtu
TOQUOP ENERGY, LLC	NV	AP4911-1146	DRAFT	750 MW PC BOILER	COAL	750	WET SCRUBBER	0.00024	lb/MMbtu
DESERT ROCK ENERGY FACILITY	NM	DRAFT	7/1/2006	(2) 750 MW SCPC BOILERS	COAL	750	LIMESTONE WET FGD, HYDRATED LIME INJECTION	0.00024	lb/MMbtu
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	660	FLUE GAS DESULFURIZATION (WET SCRUBBING)	0.0003	lb/MMBtu
WHELAN ENERGY CENTER	NE	58048	3/30/2004	BOILER, UNIT 2 UTILITY	SUBBITUMINOUS COAL	648	SPRAY DRYER ABSORBER & PM CONTROL EQUIPMENT	0.0004	lb/MMBtu
ELY ENERGY CENTER	NV	AP4911-2241	DRAFT	(2) 750 MW PC BOILERS	COAL	750	WET SCRUBBER	0.0004	lb/MMbtu
OPPD NEBRASKA CITY STATION	NE	58343C01	3/9/2005	BOILER	COAL	660	FLUE GAS DESULFURIZATION AND FABRIC FILTER	0.0004	lb/MMbtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	PC BOILERS (2)	COAL	800	DRY FGD AND BAGHOUSE	0.0004	lb/MMbtu
COMANCHE STATION	CO	04UNITPB1015	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	750	LIME SPRAY DRYER FOLLOWED BY A BAGHOUSE	0.0005	lb/MMBtu
GASCOYNE GENERATING STATION	ND	PTC 05005	6/3/2005	BOILER, COAL-FIRED	LIGNITE	620	LIMESTONE INJECTION AND SPRAY DRYER.	0.0005	lb/MMBtu
INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	UT	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950		0.0005	lb/MMBtu
TS POWER PLANT	NV	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	595	DRY SPRAY SCRUBBER & FABRIC FILTER DUST COLLECTION	0.0005764	lb/MMBtu
JK SPRUCE ELECTRIC GENERATING UNIT 2	TX	70492	1/19/2006	PULVERIZED COAL FIRED ELECTRIC STEAM BOILER	COAL	750	WET FGD	0.0008	lb/MMbtu
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	PRB COAL	7675 MMBtu/hr	LIME SPRAY DRYER FLUE GAS DESULFURIZATION	0.0009	lb/MMBtu

Table 4-9 RBLC Listings for Fluoride Emissions from Pulverized Coal Fired-Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	PRB COAL	600	DRY SCRUBBER AND FABRIC FILTER BAGHOUSE	0.00095	lb/MMbtu
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	CAPP COAL	600	DRY SCRUBBER AND FABRIC FILTER BAGHOUSE	0.0014	lb/MMbtu
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED CAOL BOILER	COAL	800		0.00281	lb/MMBtu
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER	COAL	7800 MMBtu/hr	NONE INDICATED	0.00425	lb/MMbtu
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	LIGNITE	800	NONE INDICATED	0.0103523	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	0.0165672	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	0.0165672	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	COAL	6700 MMBtu/hr	NONE INDICATED	0.0165672	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	COAL & NAT GAS	6700 MMBtu/hr	NONE INDICATED	0.0165672	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	6750 MMBtu/hr	NONE INDICATED	0.0172973	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	6750 MMBtu/hr	NONE INDICATED	0.0172973	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	COAL & NAT GAS	6750 MMBtu/hr	NONE INDICATED	0.0172973	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	COAL	6750 MMBtu/hr	NONE INDICATED	0.018963	lb/MMBtu

Prepared by: PMH 1/10/08
Checked by: JDF 1/10/08

4.3.8 BACT Demonstration for Sulfuric Acid Mist (H_2SO_4) Emissions from the Supercritical Pulverized Coal Boiler

H_2SO_4 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 H_2SO_4 is therefore highly dependent on coal sulfur content and the presence of oxidizing catalysts. The size of H_2SO_4 particle formation can be dependent on the gas cooling rate. H_2SO_4 is an acid gas, and can be controlled by the same technologies available for control of SO_2 emissions. The control technologies and strategies for control of H_2SO_4 are similar to those technologies and strategies for control of SO_2 emissions with the addition of sorbent injection technology.

Step 1 – Identify All Control Technologies

<u>Lower Emitting Process or Practice – Coal Selection</u>

Emissions of Sulfur Dioxide (SO_2) result from the oxidation of sulfur present in the coal during the combustion process. Therefore, coal source selection can have an impact on SO_2 emissions, and corresponding SO_3 formation (leading to emissions of H_2SO_4) from a coal fired boiler.

<u>Lower Emitting Process or Practice – Coal Cleaning</u>

Coal cleaning, also called coal beneficiation, or coal washing, is a cleaning process in which mineral ash matter is removed from mined coal to produce a "cleaner" coal. Coal cleaning is generally performed in order to remove impurities in the coal to improve the heat content of the coal, thereby improving power plant capacity, reduce maintenance costs at power plants and extend plant life. Coal cleaning is also performed to reduce the sulfur content in the coal. This reduction in sulfur content in the coal reduces the amount of sulfur available to form H_2SO_4 in the system exhaust gas.

<u>Lower Emitting Process or Practice – Coal Refining</u>

Coal refining is a mechanical and thermal process to remove moisture, sulfur, nitrogen, and heavy metals from coal. Also, as a result of the refining process, the ash content and moisture of the coal can be lowered, as well as increasing the heat content of the coal. Coal refining processes include processes still in the research and development stage, such as patented technologies for conversion of coal to char, a "clean" boiler fuel, and processes already in limited operation such as the Evergreen Energy, Inc. K-Fuel patented pre-combustion coal refining process. A reduction in the sulfur content in the coal would reduce the amount of sulfur available to form H_2SO_4 in the system exhaust gas.

Lower Emitting Process or Practice – Low Oxidation Catalyst

Low oxidation catalysts can be used to reduce the conversion of SO_2 to SO_3 in the exhaust flue gas stream, thereby reducing the amount of formation of H_2SO_4 emissions.

Wet Scrubber

Wet scrubbers systems are often used as Flue Gas Desulfurization (FGD) systems, where they are used to control emissions of SO_2 from oil and coal combustion sources from industrial sources and electrical utilities. Wet scrubbers can also be used in the control of H_2SO_4 emissions. The H_2SO_4 is removed from the flue gas by sorption and reaction with the reagent slurry created by the wet scrubber. Reagents commonly used in the process include lime and limestone. Additives, such as magnesium, can be added to the reagent materials to further improve the reaction of the reagent with the H_2SO_4 present in the gas stream. The by-products of the wet scrubber are in a wet slurry form and must be dewatered prior to handling and further disposal. Wastewaters generated through the wet scrubbing process may also require some level of treatment.

Spray Dryer Absorber (Dry Scrubber)

In a spray dryer absorber (SDA), or spray dryer, a fine spray of reagent slurry is atomized and comes into contact with the hot exhaust gas, or flue gas. Lime is the typical reagent used in an SDA unit. A significant part of the acidic components of the flue gas, including H_2SO_4, are rapidly absorbed into the alkaline droplets, with the water/moisture content present being evaporated simultaneously. Control of exhaust gas distribution, slurry flow rate, and spray droplet size ensure that the droplets introduced into the gas stream are effectively dried to a fine powder before touching the chamber walls of the spray dryer unit or exiting the spray dryer system. A portion of the reacted product is collected and discharged from the spray dryer absorber. The treated flue gas is then discharged to a fabric filter baghouse, or other PM control device, where additional reacted product is collected from the exhaust gas stream.

Circulating Dry Scrubber

A CDS is similar in concept and reaction chemistry to a spray dryer absorber (SDA). In a CDS system, a circulating fluidized bed arrangement is used for contacting the sorbent reagent, lime, with the H_2SO_4 present in the flue exhaust gas. In a spray dryer absorber, the reaction products exit the system in a dry form and are collected down stream in a fabric filter baghouse or other PM control device.

Regenerable Wet Scrubber

The significant difference between a regenerable wet scrubber and a standard wet scrubber, as described above, is the fact that the regenerable system recycles the spent sorbent back into the system for reuse, or regenerates the sorbent for further processing into other products. Standard wet scrubbers, and the described spray dryer absorber and circulating dry scrubbers described above, are once-through systems where the spent sorbent is collected and either disposed of as a waste or utilized and sold as a by-product (i.e. gypsum). Regenerable wet scrubbers utilize ammonia, amine, sodium sulfite, or other reagents as the sorbent material for removal of H_2SO_4 emissions from the exhaust flue gas. Regenerable wet scrubbers reportedly achieve H_2SO_4 emissions reductions comparable to that of non-regenerable wet scrubbers.

Activated Carbon Flue Gas Desulfurization

In this system, activated carbon is used as the sorbent for removal of H_2SO_4 emissions. Activated carbon is injected into the flue gas exhaust stream through a series of header nozzles upstream of a fabric filter baghouse or other Particulate Matter (PM) control device. A portion of the reacted carbon and fly ash collected by the PM control device could be recycled and injected back into the flue gas exhaust stream to minimize the need for fresh activated carbon, making the process a partially “regenerable” process.

Sorbent Injection and Wet Scrubber

One potential control technology is the combination of sorbent injection with a wet scrubber. A reagent, such as lime or limestone, is injected into the exhaust gas stream between the air heater and the PM control device. Sorbent injection technology could be used in conjunction with a wet scrubber device.

Sorbent Injection and Dry Scrubber

One potential control technology is the combination of sorbent injection with a dry scrubber. A reagent, such as lime or limestone, is injected into the exhaust gas stream between the air heater and the PM control device. Sorbent injection technology could be used in conjunction with a dry scrubber device.

Wet Electrostatic Precipitator (WESP)

WESP remove PM from the exhaust gas stream, including H_2SO_4. In a WESP unit, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. The wet effluent is collected, and often treated on-site.

Step 2 – Eliminate Technically Infeasible Options

Lower Emitting Process or Practice – Coal Selection

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. Therefore, coal selection is determined to be technically feasible for this project.

Lower Emitting Process or Practice – Coal Cleaning

Coal washing involves removing the sulfur from the fuel before combusting it in a boiler. The majority of the sulfur in the coal is organic and is chemically bonded in the molecular structure of the coal itself. 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. However, the pyritic sulfur contents of PRB and Illinois #6 coals is low, with a pyritic sulfur content of approximately 0.05% for PRB coals and approximately 2.15% for Illinois #6 coals. Assuming coal washing could remove 40% of the pyritic sulfur content of the coal, less than 1% of the sulfur (and corresponding H_2SO_4 emissions) of the use of Illinois #6 coals would be expected. Therefore, coal washing would be ineffective because there would be little sulfur content removed by the process. Also, were these coals to be washed the moisture content of the coal would be increased, and the heating value of the coal would be degraded. This would lead to an increase in the amount of coal burned, and a potential subsequent increase in pollutant emissions. Therefore, due to the minimal expected reduction in SO_2 emissions, and potential increase in emissions due to the consumption of more coal, coal cleaning is not a technically feasible option for the facility for reduction of H_2SO_4 emissions

Lower Emitting Process or Practice – Coal Refining

Coal refining is not yet a demonstrated technology for controlling H_2SO_4 emissions for a large scale coal combustion facility. A company called Evergreen Energy, Inc. is the only vendor currently found to offer refined PRB coal. The refined fuel product is called K-Fuel, and claims made regarding the use of the fuel indicate that the use of K-Fuel can lead to lower emissions of pollutants, including sulfur dioxide (and presumably H_2SO_4), nitrogen oxides, and carbon monoxide than standard PRB coal. However, the company is only operating one facility in Wyoming which has thus far seen limited production. The company hopes to produce over 50 million tons per year of K-fuel in 5 years, through full operation at the existing facility and expansion of new facilities. However, wide scale production and use, and demonstration of the improved performance of the K-fuel have yet to be conducted.

Based on the current lack of sufficient supply of coal refining facilities, coal refining is not considered an available technology for H_2SO_4 emissions reduction. Therefore, coal refining is determined to be technically infeasible for this project.

Lower Emitting Process or Practice – Low Oxidation Catalyst

Low oxidation catalysts have been used in practice, and are considered technically feasible for this project.

Wet Scrubber

Wet scrubbers have been demonstrated in wide scale use on coal-fired boilers and are available from a number of vendors. Wet scrubbers are therefore considered to be technically feasible.

Spray Dryer Absorber (Dry Scrubber)

Dry scrubbers have been demonstrated in wide scale use on coal fired boilers and are available from a number of vendors. Dry scrubbers are therefore considered to be technically feasible.

Circulating Dry Scrubber

Circulating Dry Scrubbers have not yet been demonstrated on a coal-fired boiler of greater than 250 MW. The size and scale differences between the proposed utility boiler and the boilers on which this technology has been demonstrated would likely lead to the requirement for further design, research, and testing for assessing viability on such a large scale unit. Circulating fluidized bed systems, as with the a circulating fluidized bed boiler, are not in use at the size and scale of the proposed utility boiler. Therefore, circulating dry scrubber systems are not considered available for this project and are considered technically infeasible for this analysis.

Activated Carbon Flue Gas Desulfurization

Although some level of H_2SO_4 removal would be expected from use of injection of activated carbon into the flue gas exhaust stream, removal efficiencies when using this technology as a stand alone control methodology are not as effective as those of other stand alone control devices, such as wet or dry scrubbers. Research data has shown that concentrations of NO_X in the flue gas exhaust stream, specifically nitrogen monoxide (NO), can lead to inhibition of the catalytic effect of the porous carbon material, leading to deteriorated desulfurization performance. This deteriorated desulfurization performance can lead to the requirement for an increasing amount of activated carbon use, thereby increasing the treatment costs. Activated carbon desulfurization would not be expected to achieve a significant reduction in SO_2 emissions. Therefore, for the above listed reasons, the use of activated carbon FGD for removal of H_2SO_4 emissions is considered technically infeasible for this project.

Sorbent Injection and Wet Scrubber

There is some data to indicate that there would be an H_2SO_4 emissions reduction benefit from use of sorbent injection along with a wet scrubber. For these reasons, use of duct sorbent injection in conjunction with a wet scrubber is considered technically feasible for this project.

Sorbent Injection and Dry Scrubber

There is limited operating data available to indicate that there would be a substantial H_2SO_4 emissions reduction benefit from use of sorbent injection along with a dry scrubber. Inclusion of duct sorbent injection with a dry scrubber would lead to increased capital and annualized operating costs, with no assurance of an improved system performance from use of a dry scrubber alone. Also, a secondary concern for use of sorbent injection with a dry scrubber is the potential for interference of the duct sorbent material with the operation of the dry scrubber. A sorbent material present in the flue gas exhaust stream could potentially interfere with the ability of the spray dryer absorber (dry scrubber) to evaporate the moisture in the reagent slurry, thus impacting the effectiveness of the unit. For these reasons, use of sorbent injection in conjunction with a dry scrubber is considered technically infeasible.

Wet Electrostatic Precipitator (WESP)

WESP units have been shown to remove H_2SO_4 mists from exhaust streams and are considered technically feasible.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

The feasible control technologies found during Step 2 of this analysis include coal selection, low oxidation catalysts, wet scrubbers, sorbent injection with wet scrubbers, spray dryer absorbers (dry scrubbers), and WESP. Reviews were conducted of technical publications, the USEPA RBLC, and vendor information to determine the control efficiencies of each of these identified technically feasible H_2SO_4 reduction technologies. There are not many instances where the comparative performance of control technologies for H_2SO_4 emissions control has been evaluated, and limited and conflicting data exists as to the effectiveness of differing control technologies. A review of data on the RBLC database includes a wide variety of controls deemed applicable historically for BACT for coal-fired boilers, including wet scrubbers, dry scrubbers, dry scrubber and baghouse in coordination, baghouse and wet scrubber in coordination, limiting of fuel sulfur content, and coordination of an ESP, dry scrubber, and WESP unit.

Energy Impacts

Energy penalties are much more significant for a wet scrubber and WESP than for a dry scrubber. With wet scrubbers, greater energy requirements exist due to greater system pressure drops and larger energy requirements for ancillary equipment, such as water recycling pumps, slurry dewatering pumps, etc. Utilization of a wet scrubber can demand greater than 2 percent of the gross power generation of the facility, while dry scrubbers can demand typically around 1 percent of the gross power generation of the facility. Utilization of sorbent injection along with a wet scrubber would be expected to add minimal power demand to the system. Any significant power demand for the sorbent injection system would come from power required to handle or process the sorbent powder or slurry.

Based on data in an USEPA Air Pollution Training Institute publication on Electrostatic Precipitator Operation, the power required to operate a wet electrostatic precipitator can be around 1000 watts per 1000 acfm, with limited collection efficiency degradation at 705 watts per 1000 acfm. For the estimated air flow currently available for the site, this could lead to ESP power requirements from 2 to 3 MW. Therefore, power generation requirements for a wet scrubber or a WESP unit would be more significant than the power generation requirements for a dry scrubber. Obviously, if a wet scrubber was used in tandem with a WESP unit, significant demands of the gross power generation of the facility would be required to operate the facility air pollution control equipment.

Environmental Impacts

Wet scrubbers have an added collateral environmental benefit over dry scrubbers in that they are more effective in the capture of secondary acid gases in the flue gas exhaust stream than a dry scrubber, including reactive mercury, hydrogen chloride, and fluorides. Water consumption is an important environmental impact when evaluating wet scrubbers and dry scrubbers, since wet scrubbers have a more significant water usage than dry scrubbers. However, dry scrubbers are not truly “dry”, as water is used in preparation of the reagent slurry which is atomized and injected into the exhaust gas stream.

Another significant environmental impact involves the generation of solid waste and wastewaters from wet scrubbers and dry scrubbers. Wastewater from a wet scrubber would require more specialized handling and treatment than a dry scrubber, since dry scrubber systems do not produce blowdown or a wastewater stream. Sorbent injection would not be expected to produce a wastewater stream. Wet scrubbers can produce a solid waste stream (gypsum) which can be marketable depending on the quality of the gypsum produced, and the status of the current market. Dry scrubbers produce a solid waste stream with little to no commercial value that is traditionally disposed in a solid waste facility.

WESP units create wastewaters, which would have to be treated and handled in accordance with applicable regulations. Obviously, use of a WESP unit in conjunction with a wet scrubber would increase the amount of wastewaters generated at the facility.

Economic Impacts

The BACT analysis for SO_2 emissions has proposed use of a wet scrubber, and the PM BACT analysis has proposed use of a fabric filter baghouse. Also, the BACT evaluation for SO_2 emissions in Section 4.3.5 determined that coal selection to reduce SO2 (and therefore SO_3 and H_2SO_4 emissions) was not feasible. Use of a sorbent injection system in conjunction with a fabric filter baghouse and wet scrubber will not lead to a significant economic impact.

Step 4 – Evaluate Remaining Control Technologies

As stated above in Step 3, there are not many instances where the performance of control technologies for H_2SO_4 emissions control has been evaluated and limited and conflicting data exists as to the effectiveness of differing control technologies. A review of data on the RBLC database includes a wide variety of controls deemed applicable historically for BACT for coal-fired boilers, including wet scrubbers, dry scrubbers, dry scrubber and baghouse in coordination, baghouse and wet scrubber in coordination, limiting of fuel sulfur content, and coordination of an ESP, dry scrubber, and WESP unit. Data exists which indicates that a facility installing a wet scrubber may or may not install a WESP unit.

Therefore, for the above listed reasons, utilization of a wet scrubber with sorbent material injection is chosen as the top control option for control of H_2SO_4 emissions. Utilization of a baghouse system (for PM control), in addition to sorbent injection for mercury control utilizing activated carbon, should provide some additional added control of H_2SO_4 emissions. This level of control has been proposed as BACT in recent PSD permit applications.

Energy Impacts

While wet scrubber systems at the facility would use approximately 2 percent of the gross power generation of the facility, dry scrubbing systems would use almost 1 percent of the gross power generation of the facility. This approximately 1 percent difference in gross power demand does not preclude the use of a wet scrubber system at the facility. Utilization of sorbent injection along with a wet scrubber would be expected to add minimal power demand to the system. Any significant power demand for the sorbent injection system would come from power required to handle or process the sorbent powder or slurry.

Environmental Impacts

Wet scrubbers have an added collateral environmental benefit over dry scrubbers in that they are more effective in the capture of secondary acid gases in the flue gas exhaust stream than a dry scrubber, including reactive mercury, hydrogen chloride, and fluorides. Water consumption for a wet scrubber system would be higher than the water consumption for a dry scrubber, due to the inherent design difference present between a wet scrubber and a dry scrubber. However, the additional water consumption necessary for operation of a wet scrubber does not preclude the use of a wet scrubber at the facility. The waste stream present from a wet scrubber (gypsum) is a potentially saleable product. Waste streams generated by a wet scrubber are inherently more saleable or recyclable than those waste streams generated by a dry scrubber. Sorbent injection would not be expected to produce a wastewater stream. However, there would be additional solid wastes generated from use of the sorbent injection materials.

Economic Impacts

As discussed above, a wet scrubber in conjunction with sorbent injection has been chosen as the most effective control of H_2SO_4 emissions, based on recent BACT determinations and achieved emissions levels of H_2SO_4. Use of a sorbent injection system will not lead to a significant economic impact.

Step 5 – Selection of BACT

A summary of recent H_2SO_4 BACT evaluations conducted for similar projects can be found in Table 4-10 below. Utilization of a wet scrubber (wet flue gas desulfurization) with sorbent injection is believed to achieve the maximum amount of H_2SO_4 emissions reduction available. BACT for H_2SO_4 emissions is proposed as use of a wet scrubber with sorbent injection and an emission limit of 0.005 lb/MMBtu on a 3-hr average basis. This level of control and emission limit has been proposed as BACT on similar recent projects, such as the Toquop Energy, LLC facility in Nevada. The lowest demonstrated emission limit value from the RBLC database is 0.0014 lb/MMBtu from the Santee Cooper Cross Generation Station Unit 3. Preliminary indications from SC DHEC are that stack testing has shown compliance with this emission limit. However, due to the variation in the types of coal used between the current project and Santee Cooper Cross, this value is not deemed appropriate for this evaluation.

Table 4-10 RBLC Listings for Sulfuric Acid Mist (H_2SO_4) Emissions from Pulverized Coal-Fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	
TS POWER PLANT	NV	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	595	DRY SPRAY SCRUBBER & FABRIC FILTER DUST COLLECTION	0.0010	lb/MMBtu
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	660	FLUE GAS DESULFURIZATION (WET SCRUBBING)	0.0014	lb/MMBtu
HUGO GENERATING STATION	OK	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	UNKNOWN	750	WET FLUE GAS DESULFURIZATION	0.0037	lb/MMBtu
JK SPRUCE ELECTRIC GENERATING UNIT 2	TX	N/A	1/19/2006	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	COAL	750	WET FGD AND BAGHOUSE	0.0037	lb/MMbtu
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	COAL	112	LIMESTONE INJECTION	0.0039	lb/MMBtu
DESERT ROCK ENERGY FACILITY	NM	N/A	7/1/2006	(2) 750 MW SCPC BOILERS	COAL	750	LIMESTONE WET FGD, HYDRATED LIME INJECTION BEFORE FF	0.004	lb/MMBtu
ELY ENERGY CENTER	NV	AP4911-2241	DRAFT	(2) 750 MW PC BOILERS	COAL	750	FF AND WET SCRUBBER	0.004	lb/MMbtu
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	PRB COAL	7675 MMBtu/hr	LIME SPRAY DRYER FLUE GAS DESULFURIZATION	0.0042	lb/MMBtu
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER	SUBBITUMINOUS COAL	660	DRY FLUE GAS DESULFURIZATION & FABRIC FILTER	0.0042	lb/MMBtu
COMANCHE STATION	CO	04UNITPB1015	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	750	LIME SPRAY DRYER FOLLOWED BY A BAGHOUSE	0.0042	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	0.0043	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	COAL	6700 MMBtu/hr	FUEL S CONTENT LIMITED	0.0043	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	COAL	6700 MMBtu/hr	NONE INDICATED	0.0043	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	COAL & NAT GAS	6700 MMBtu/hr	NONE INDICATED	0.0043	lb/MMBtu
INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	UT	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950	BAGHOUSE/FABRIC FILTER AND WET FLUE GAS DESULPHURIZATION	0.0044	lb/MMBtu
INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	UT	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	COAL	950	BAGHOUSE/FABRIC FILTER AND WET FLUE GAS DESULPHURIZATION	0.0044	lb/MMbtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	6750 MMBtu/hr	FUEL S CONTENT LIMITED	0.0045	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	6750 MMBtu/hr	FUEL S CONTENT LIMITED	0.0045	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	COAL & NAT GAS	6750 MMBtu/hr	NONE INDICATED	0.0045	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	COAL	6750 MMBtu/hr	NONE INDICATED	0.0049	lb/MMBtu

Table 4-10 RBLC Listings for Sulfuric Acid Mist (H_2SO_4) Emissions from Pulverized Coal-Fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	COAL	750	PROPER BOILER DESIGN AND CONTROL TECHNOLOGY, ESP, FGD, AND WESP	4.97E-03	lb/MMBtu
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	(2) 750 MW PC BOILERS	COAL	750	PROPER BOILER DESIGN AND CONTROL TECHNOLOGY, ESP, FGD, AND WESP	0.00497	lb/MMbtu
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	500	FGD SYSTEM	0.005	lb/MMBtu
OTTER TAIL POWER COMPANY	SD	N/A	4/1/2006	600 MW SCPC BOILER	COAL	600	WET SCRUBBER AND BAGHOUSE	0.005	lb/MMBtu
TRIMBLE COUNTY GENERATING STATION	KY	N/A	7/6/2005	SUPER CRITICAL PULVERIZED COAL	COAL	750	WET FGD AND WET ESP	0.005	lb/MMbtu
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	COAL	600	DRY FGD AND BAGHOUSE	0.005	lb/MMbtu
TOQUOP ENERGY, LLC	NV	AP4911-1146	DRAFT	750 MW PC BOILER	COAL	750	WET SCRUBBER AND SORBENT INJECTION	0.005	lb/MMbtu
GASCOYNE GENERATING STATION	ND	PTC 05005	6/3/2005	BOILER, COAL-FIRED	LIGNITE	620	LIMESTONE IJECTION AND SPRAY DRYER.	0.0061	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER , UNIT 1 - SN-01	SUB-BITUMINOUS COAL	800	DRY FGD/FABRIC FILTER	0.0061	lb/MMBtu
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER - SN-01	SUB-BITUMINOUS COAL	800	DRY FGD/FABRIC FILTER	0.0061	lb/MMBtu
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	COAL	390	DRY FLUE GAS DESULFURIZATION (FGD) - SPRAY DRY ABSORBER	0.0064	lb/MMBtu
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	COAL	390	DRY FLUE GAS DESULFURIZATION (FGD) SPRAY DRY ABSORBER	0.0064	lb/MMBtu
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	DRY SOLID INJECTION W/ FABRIC FILTER	0.0075	lb/MMBtu
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED COAL BOILER	COAL	800	NONE INDICATED	0.0155	lb/MMBtu
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	LIGNITE	7863 MMBtu/hr	LIMESTONE WET SCRUBBING	0.0312	lb/MMBtu

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Checked by: JDF 1/10/08

4.3.9 BACT Demonstration for Mercury (Hg) Emissions from the Supercritical Pulverized Coal Boiler

Hg is present in coal in trace amounts, and is released into the main boiler exhaust flue gas during combustion. According to the USEPA document *Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update (2005)* the Hg content in coal is approximately 0.1 parts per million (ppm) on average. Design coal analysis data for the facility indicates that both the PRB and Illinois #6 coals used in the 50/50 blend at the facility contain an average of approximately 0.09 ppm Hg.

Hg is typically present in the exhaust flue gas in three distinct forms. Hg is typically present in the flue gas stream as either an elemental Hg vapor, particle bound Hg, or as a vapor of an oxidizer Hg species (Hg^{2+}). Elemental Hg is typically regarded as the most difficult form of Hg to control. The chemical form of the Hg present in the flue gas stream can have a significant impact on the effectiveness of the control strategies employed for control of Hg emissions.

Step 1 – Identify All Control Technologies

<u>Lower Emitting Process or Practice – Coal Refining</u>

Coal refining is a mechanical and thermal process to remove moisture, sulfur, nitrogen, and heavy metals from coal. Also, as a result of the refining process, the ash content and moisture of the coal can be lowered, as well as increasing the heat content of the coal. Coal refining processes include processes still in the research and development stage, such as patented technologies for conversion of coal to char, a "clean" boiler fuel, and processes already in limited operation such as the Evergreen Energy, Inc. K-Fuel patented pre-combustion coal refining process. The Alaska Cowboy Coal Power Consortium has conducted small scale demonstration tests to remove a portion of the Hg content of the coal. The process removes Hg from the coal utilizing a low temperature ambient pressure method. However, the process has yet to be demonstrated on a full scale. A reduction in the Hg content in the coal would reduce the amount of Hg available and thereby released in the system exhaust gas.

Lower Emitting Process or Practice – Fuel Blending

One of the primary reactions of Hg in the flue gas stream is with gas phase chlorine. Reactions with gas phase chlorine lead to formation of mercuric chloride ($HgCl_2$), which can be more effectively removed from the flue gas stream than elemental Hg. Gas phased Hg oxidation is a slow process, and is dependent on the amount of chlorine present in the flue gas. The amount of chlorine present in the flue gas is proportional to the amount of chlorine present in the coal being combusted.

Western sub-bituminous coals, such as PRB coals, typically have much lower chlorine content than that of Eastern bituminous coals, such as Illinois #6 coal. Therefore, blending of sub-bituminous and bituminous coals for combustion in the main facility boiler could theoretically lead to increased gas phase reactions in the flue gas with chlorine, thereby increasing the effective capture of Hg and reducing Hg emissions. However, limited data is available on the effectiveness of fuel blending as a control strategy for Hg emissions.

Lower Emitting Process or Practice – Oxidizing Chemicals

Introduction of chlorine or other halogens into the flue gas stream could potentially lead to increased gas phase reactions in the flue gas, thereby increasing the effective capture of mercury and reducing mercury emissions. However, limited data is available on the effectiveness of such systems, and the effectiveness of use of oxidizing chemicals would likely be affected by the type and quality of coal being combusted, and the type and design of additional pollution control equipment in use at the facility.

Lower Emitting Process or Practice – Unburned Carbon (UBC) Enhancement

Increasing the unburned carbon in the coal ash could potentially reduce Hg emissions through decreasing the amount of Hg released into the flue gas stream and by providing carbon present for reaction with Hg. However, adjusting combustion conditions in the main boiler to increase the unburned carbon content present in the ash could have detrimental effects to the efficiency and operation of the main boiler, and could negatively effective emissions of other pollutants, such as PM and SO_2 since effectively more coal would have to be burned.

Lower Emitting Process or Practice – Chemical Additive Injection to SCR

Chemicals added to the SCR control device could potentially increase the oxidation of elemental Hg and reduce the chemical reduction of oxidized Hg in a wet FGD system. However, limited information is available to date on the effectiveness of such practices.

Fabric Filter Baghouse and Wet Scrubber

Fabric filter baghouses have been shown to be relatively more effective at control of Hg emissions than ESP control devices. The amount of control achieved by ESP devices is through capture of particle bound Hg. Therefore, the effectiveness of an ESP system at control of Hg emissions would be highly dependent on the amount of particle bound Hg present in the flue gas stream. Fabric filter baghouses are likely more effective at control of Hg emissions than ESPs due to the filter cake collecting on the outside of the baghouse filter bags. The filter cake will enhance gas phase particle reactions, increasing adsorption of oxidized Hg and potentially oxidation of elemental Hg.

Wet scrubbers systems are often used as FGD systems, where they are used to control emissions of SO_2 from oil and coal combustion sources from industrial sources and electrical utilities. Wet scrubbers can also be used in the control of Hg emissions. Oxidized Hg, present in such forms as $HgCl_2$, is an acid gas and water soluble, therefore potentially effectively removed by a wet scrubber device. However, effectiveness of the wet scrubber in removal of Hg emissions could be reduced by the chemical reduction of oxidized Hg to elemental Hg in the wet scrubber, leading to re-emission of Hg. As stated in the USEPA document *Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update (2005)*, "*Experience has shown that* Hg^{2+} *reduction and reemission may be more difficult to avoid in magnesium-enhanced lime (MEL) scrubbers due to the much higher sulfite concentration in those systems*."

Spray Dryer Absorber (Dry Scrubber) and Fabric Filter Baghouse

Spray Dryer Absorbers, or dry scrubbers, used in conjunction with fabric filter baghouses have been found to provide greater than 90 percent control efficiency for mercury with bituminous coal combustion. However, control efficiencies when burning sub—bituminous coals is approximately 25 percent, which is much less than the effectiveness of fabric filter baghouses alone. One possibility is that the Spray Dryer Absorber is effectively removing the chlorine (as HCl), and that bituminous coals contain enough excess chlorine that chlorine (as HCl) scrubbing by the Spray Dryer Absorber is not an issue for bituminous coals.

Selective Catalytic Reduction (SCR)

Use of SCR units potentially enhance oxidation of elemental mercury, thus enabling more effective control of mercury in downstream air pollution control devices.

Sorbent Injection

Unlike the pollution control devices listed above, sorbent injection would be conducted primarily for removal of Hg emissions, and not achieving Hg removal as a co-benefit (i.e. fabric filter baghouse). Injection of dry sorbents such as PAC into flue gas streams has been used for control of Hg emissions from waste combustors, and has been tested at electric utility units in the United States.

Dry sorbent is typically injected into the ductwork upstream of a PM control device, either an ESP or fabric filter baghouse. The sorbent is typically pneumatically injected as a powder. The sorbent provides an active surface for adsorption of Hg present in the flue gas stream, thus promoting formation of particle bound Hg that can be removed by a particulate matter control device, such as a fabric filter baghouse. As discussed above, due to the potential secondary reaction effects of dry sorbents on the filter cake of a fabric filter baghouse, a fabric filter baghouse would be a more effective PM control device when used in conjunction with a sorbent injection system for control of Hg emissions.

Step 2 – Eliminate Technically Infeasible Options

Lower Emitting Process or Practice – Coal Refining

Coal refining is a mechanical and thermal process to remove moisture, sulfur, nitrogen, and heavy metals from coal. Based on the current lack of sufficient supply of coal refining facilities, and the lack of full scale testing of certain methods such as the Cowboy Coal method, coal refining is not considered an available technology for H_2SO_4 emissions reduction. Therefore, coal refining is determined to be technically infeasible for this project.

Lower Emitting Process or Practice – Fuel Blending

Western sub-bituminous coals, such as PRB coals, typically have much lower chlorine content than that of Eastern bituminous coals, such as Illinois #6 coal. Therefore, blending of sub-bituminous and bituminous coals for combustion in the main facility boiler could theoretically lead to increased gas phase reactions in the flue gas with chlorine, thereby increasing the effective capture of Hg and reducing Hg emissions. The design criteria for the facility is to burn a 50/50 by weight blend of western sub-bituminous PRB coal and eastern bituminous Illinois #6 coal. Therefore, fuel blending is considered technically feasible for this project.

Lower Emitting Process or Practice – Oxidizing Chemicals

Introduction of chlorine or other halogens into the flue gas stream could potentially lead to increased gas phase reactions in the flue gas, thereby increasing the effective capture of Hg and reducing Hg emissions. However, limited data is available on the effectiveness of such systems, and the effectiveness of use of oxidizing chemicals would likely be affected by the type and quality of coal being combusted, and the type and design of additional pollution control equipment in use at the facility. Therefore, use of oxidizing chemicals is considered technically infeasible for this project.

Lower Emitting Process or Practice – Unburned Carbon (UBC) Enhancement

Adjusting combustion conditions in the main boiler to increase the unburned carbon content present in the ash could have detrimental effects to the efficiency and operation of the main boiler, and could negatively effect emissions of other pollutants, such as PM. Therefore, unburned carbon enhancement is considered technically infeasible for this project.

Lower Emitting Process or Practice – Chemical Additive Injection to SCR

Chemicals added to the SCR control device could potentially increase the oxidation of elemental Hg and reduce the chemical reduction of oxidized Hg in a wet FGD system. However, limited information is available to date on the effectiveness of such practices. Therefore, use of chemical additive injection to the SCR device is considered technically infeasible for this project.

Fabric Filter Baghouse and Wet Scrubber

BACT evaluations conducted above for the main facility boiler for PM and SO_2 emissions determined that a fabric filter baghouse and wet scrubber were BACT controls to be utilized at the facility. Fabric filter baghouses and wet scrubbers are in extensive use as pollution control devices for electric utility boilers. Therefore, use of a fabric filter baghouse in conjunction with a wet scrubber is considered technically feasible for control of Hg emissions.

Spray Dryer Absorber (Dry Scrubber) and Fabric Filter Baghouse

BACT evaluations conducted above for the main facility boiler for PM and SO_2 emissions determined that a fabric filter baghouse and wet scrubber were BACT controls to be utilized at the facility. Therefore, use of a fabric filter baghouse in conjunction with a spray dryer absorber is considered technically infeasible for control of Hg emissions for this project.

Selective Catalytic Reduction (SCR)

Use of SCR units potentially enhance oxidation of elemental Hg, thus enabling more effective control of mercury in downstream air pollution control devices. Use of an SCR unit has been proposed as BACT for control of NO_X emissions from the facility. Therefore, use of an SCR system for control of Hg emissions is feasible for this project.

Sorbent Injection

Sorbent injection would be conducted primarily for removal of Hg emissions, and not achieving Hg removal as a co-benefit (i.e. fabric filter baghouse). Injection of dry sorbents such as PAC into flue gas streams has been used for control of Hg emissions from waste combustors, and has been tested at electric utility units in the United States. Therefore, use of sorbent injection for control of Hg emissions is considered technically feasible for this process.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

The only feasible control technology found during Step 2 not already determined as BACT earlier in this evaluation (i.e. fabric filter baghouse and wet scrubber) or determined as a design criteria for the facility (i.e. fuel blending) is use of sorbent injection through use of PAC. Research data and evaluations conducted to date indicate that a greater than 90 percent reduction in Hg emissions could be achieved through use of an SCR, PAC sorbent injection system, fabric filter baghouse, and wet scrubber system.

Energy Impacts

Utilization of a PAC sorbent injection system would be expected to add minimal power demand to the system compared to other facility pollution control devices. Any significant power demand for the sorbent injection system would come from power required to handle or process the sorbent powder.

Environmental Impacts

The main environmental impact associated with use of the activated carbon sorbent injection system is generation of solid waste materials now containing small amounts of Hg. A study by Consol Energy, *The Evolution of Mercury From Coal Combustion Materials and By-products (2003)* evaluated the fate of Hg collected on fly ash, which are materials collected by the particulate matter control devices, on flue gas desulfurization solids, and on bottom ash materials. The objective of the study was to address the concern of Hg evolution into the ecosystem following disposal of waste materials from a coal fired power plant potentially containing Hg.

Samples were taken from fly ash, FGD sludge, and bottom ash waste streams and analyzed for leachable Hg, or that Hg which would be released into the surrounding soils following disposal. Data showed less than the analytical detection limit of 1.0 parts per billion (ppb) of Hg in the filtrates of all fly ash, FGD sludge, and bottom ash samples analyzed. In order for a waste stream to be considered a hazardous waste due to the concentration of Hg, it must contain greater than 200 ppb leachable Hg.

Groundwater samples were also taken in areas of active FGD sludge disposal and ash impoundments. Groundwater samples analyzed were found to contain less than the Hg analytical detection limit of 1 ppb.

Economic Impacts

Utilizing the USEPA Air Pollution Control Cost Manual, and data provided in the USEPA document *Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update* and the DOE report *Preliminary Cost Estimate of Activated Carbon Injection for Controlling Mercury Emissions from an Un-Scrubbed 500 MW Coal-Fired Power Plant*, the total annual cost of a PAC sorbent injection system would be a minimum of approximately $1.6 million. At this cost, the $/ton cost effectiveness of the system would be much greater than $10,000/ton, at a cost of greater than $60,000/ton. The $/ton cost effectiveness of the system is so high due to the low concentration of Hg present (0.09 ppm) in the design coal for the plant, leading to a low uncontrolled emission rate of Hg. However, due to the underlying environmental concerns regarding emissions of Hg, requirements under the CAMR and NSPS Subpart HHHH, use of an activated carbon sorbent injection system is considered economically feasible for this project.

Step 4 – Evaluate Remaining Control Technologies

Utilization of an activated carbon sorbent injection system, in conjunction with collateral benefits from use of additional pollution control devices determined as BACT for differing pollutants, is chosen as the top control option for control of Hg emissions.

Energy Impacts

Utilization of a PAC sorbent injection system would be expected to add minimal power demand to the system compared to other facility pollution control devices. Any significant power demand for the sorbent injection system would come from power required to handle or process the sorbent powder. No energy impacts would preclude the use of activated carbon sorbent injection.

Environmental Impacts

The main environmental impact associated with use of the activated carbon sorbent injection system is generation of solid waste materials now containing small amounts of Hg. As discussed above, study data has indicated that environmental impacts from disposal of solid waste materials from air pollution control equipment potentially containing Hg at a coal-fired power plant are not a direct environmental concern for this project. Therefore, environmental impacts from use of activated carbon sorbent injection do not pose a concern.

Economic Impacts

The $/ton cost effectiveness of an activated carbon sorbent injection system is so high due to the low concentration of Hg present (0.09 ppm) in the design coal for the plant, leading to a low uncontrolled emission rate of Hg. However, due to the underlying environmental concerns regarding emissions of Hg, and regulatory requirements under the CAMR and NSPS Subpart HHHH, use of an activated carbon sorbent injection system is considered economically feasible for this project. Therefore, economic concerns do not preclude the use of activated carbon sorbent injection for this project.

Step 5 – Selection of BACT

A summary of recent mercury BACT evaluations conducted for similar projects can be found in Table 4-11 below. Utilization of an activated carbon sorbent injection system is proposed as BACT for the main facility boiler. An emission limit of 15×10^{-6} lb/MW-hr has been deemed appropriate based on the level of control and emission limits proposed as BACT on similar recent projects, such as the Longleaf Energy Associates, LLC facility in Georgia.

Table 4-11 RBLC Listings for Mercury (Hg) Emissions from Pulverized Coal-Fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	Emission Limit Unit
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	500	FABRIC FILTER BAGHOUSE, SORBENT INJECTION OPTIMIZATION STUDY	1.70E-06	lb/MMBtu
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	PRB COAL	7675 MMBtu/hr	ACTIVATED CARBON	1.70E-06	lb/MMBtu
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	SCR, DRY SOLID INJECTION W/ FABRIC FILTER, AND WET LIMESTONE FORCED OXIDATION	2.39E-06	lb/MMBtu
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	COAL	750	ESP, WESP, WFGD	3.21E-06	lb/MMBtu
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	660	ESP/FLUE DESULFURIZATION/LOW NOX BURNERS, AND SCR COMBINED	3.60E-06	lb/MMBtu
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	COAL	798	NONE INDICATED	7.54E-06	lb/MMBtu
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600MW UNITS	COAL	600	NONE INDICATED	1.50E-05	lb/MW-hr
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	LIGNITE	7863 MMBtu/hr	NONE INDICATED	5.09E-05	lb/MMBtu
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED COAL BOILER	COAL	800	NONE INDICATED	1.15E-04	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	2.78E-04	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	2.78E-04	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	COAL	6700 MMBtu/hr	NONE INDICATED	2.78E-04	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	COAL & NAT GAS	6700 MMBtu/hr	NONE INDICATED	2.78E-04	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	6750 MMBtu/hr	NONE INDICATED	2.88E-04	lb/MMBtu
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	6750 MMBtu/hr	NONE INDICATED	2.88E-04	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	COAL & NAT GAS	6750 MMBtu/hr	NONE INDICATED	2.88E-04	lb/MMBtu
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	COAL	6750 MMBtu/hr	NONE INDICATED	3.16E-04	lb/MMBtu

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4.4 Auxiliary Boiler

This section contains the BACT analysis for the planned 240 MMBtu/hr auxiliary boiler unit planned for use at the facility. A summary of the BACT results for the auxiliary boiler is found in Table 4-2 above. Pollutants which exist in deminimis quantities in the boiler fuel (No. 2 fuel oil), including Lead, Mercury, and Fluorides (as HF) were not evaluated due to their low level of estimated annual emissions (< 2 lb/yr). If required, BACT emission levels for these pollutants will be established as the pollutant emission factors established in AP-42, Fifth Edition, Volume 1, Chapter 1.3.

4.4.1 BACT Demonstration for Particulate Matter (PM) Emissions from the Auxiliary Boiler

PM emissions can be affected by the grade of fuel oil fired in a boiler. PM emissions from oil fired boilers are primarily composed of particles resulting from the incomplete combustion of the oil, and are not correlated to the ash or sulfur content of the oil. Combustion of lighter distillate oil results in lower PM formation than combustion of heavier residual oils.

Step 1 – Identify All Control Technologies

Lower Emitting Process or Practice – Fuel Selection

The only applicable lower emitting process or practice would be the selection of low sulfur distillate fuel oil (0.05%) for fuel for the auxiliary boiler. The use of light distillate fuel oil for combustion would lead to lower PM emissions than use of heavier residual oils.

Fabric Filter Baghouse

Fabric filters are used for PM control in a wide variety of industries, including use as PM control on PC fired boilers, and are capable of achieving control efficiencies of 99 percent or greater. According to the USEPA's fabric filter fact sheet (2003) "*flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are the most common type of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Bags may be 6 to 9 m*

(20 to 30 ft) long and 12.7 to 30.5 centimeters (cm) (5 to 12 inches) in diameter. Groups of bags are placed in isolable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter."

Advantages of fabric filters can include the following:

4. Can provide high collection efficiencies on both coarse and fine (submicron) particulates.

5. Fabric filters are available in a large number of configurations and system designs, allowing for high flexibility in design.

6. Collected material is collected dry for subsequent processing or disposal.

Some disadvantages of fabric filters include:

4. Fabric filters can have relatively high maintenance requirements (filter bag replacement).

5. Concentrations of dusts in the collector can represent a fire or explosion hazard if a spark or flame is somehow introduced.

6. The units cannot be operated in high moisture gas streams; moisture can cause caking or plugging of the fabric filter.

Dry Electrostatic Precipitator (ESP)

Dry ESPs are used in a wide variety of source categories for control of PM emissions, and are capable of achieving control efficiencies of 99 percent or greater. The following is an excerpt from the USEPA's dry ESP fact sheet (2003):

"*An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In dry ESPs, the collectors are knocked, or* *"rapped", by various mechanical means to dislodge the particulate, which slides downward into a hopper where they are collected. The hopper is evacuated periodically, as it becomes full. Dust is removed through a valve into a dust handling system, such as a pneumatic conveyor, and is then disposed of in an appropriate manner.*"

Advantages of dry ESPs include the following:

4. Are capable of very high efficiencies, even for small particulate sizes.

5. Can be designed for a wide range of gas temperatures, and can handle high temperatures (up to 1300^o F).

6. Relatively large gas flow rates can be effectively handled.

Some disadvantages of dry ESPs include the following:

4. High capital costs and high maintenance items, such as the wire discharge electrodes.

5. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

6. Fly ash from the combustion of low sulfur coal typically has a high resistivity, and thus is difficult to collect.

Wet Electrostatic Precipitator (WESP)

A WESP is commonly used in situations where a dry ESP is not viable, such as when the material to be collected is wet, flammable, or has a high resistivity. WESPs are commonly used by the wood products and metallurgical industries, and can achieve PM control efficiencies of greater than 99 percent. The following is an excerpt from the USEPA's wet ESP fact sheet (2003).

"*An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical* *charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. The collection hoppers used by dry ESPs are replaced with a drainage system. The wet effluent is collected, and often treated on-site*."

Advantages of WESPs include the following:

5. Are capable of very high efficiencies, even for low particulate sizes.

6. Relatively large gas flow rates can be effectively handled.

7. WESPs can collect sticky particles, mists, and highly resistive or explosive dusts due to the humid atmosphere from washing in the ESP.

8. Continuous or intermittent washing with a liquid eliminates the reentrainment of particles, which dry ESPs are subject to through the rapping process.

Some disadvantages of WESPs include the following:

5. High capital costs and high maintenance items, such as the wire discharge electrodes.

6. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

7. WESPs add the complexity of a wash system, and the fact that the resulting slurry must be handled more carefully than a dry product, and can require treatment.

8. Wet ESPs are typically operated at gas stream temperatures under 190 degrees F, and usually must be constructed of non-corrosive materials.

Step 2 – Eliminate Technically Infeasible Options

Lower Emitting Process or Practice – Fuel Selection

The combustion of light distillate fuel oils results in lower levels of PM emissions than combustion of heavier residual fuel oils. Fuel selection is considered technically feasible for this analysis.

Fabric Filter Baghouse

A fabric filter baghouse is a proven technology in the control of PM/PM_{10} emissions. Data exists which indicates that oily mist from the combustion of fuel oil can clog the filter bags, thus affecting the performance and efficiency of the fabric filter baghouse. However, this technology has been demonstrated on solid fuel boilers and is considered technically feasible.

Dry Electrostatic Precipitator (ESP)

A dry ESP is a proven technology in the control of PM/PM_{10} emissions. This technology is considered technically feasible.

Wet Electrostatic Precipitator (ESP)

A WESP is a proven technology in the control of PM/PM_{10} emissions. This technology is considered technically feasible.

Step 3 – Rank Remaining Technically Feasible Control Options

The combination of the low duty cycle, 10 percent, in conjunction with the placement and configuration of the auxiliary boiler at a power plant have generally eliminated consideration of add on emission control devices. Since the primary purpose of the auxiliary boiler is for start up and shut downs of the PC boiler, it operational schedule generally precludes the use of onsite control systems.

Step 4 – Evaluate Remaining Control Technologies

Fabric filter baghouses and ESPs both provide the maximum degree of emissions reduction of PM emissions from an auxiliary boiler unit. Both controls do not have any significant collateral environmental impacts. WESP have a slight disadvantage when compared to fabric filter baghouses and dry ESPs, in that they produce a wet waste product, which can lead to additional treatment and disposal costs than with dry systems.

Energy Impacts

Although a fabric filter baghouse would require additional auxiliary power to overcome the pressure drop across the fabric filter bags, such energy requirements would not be enough to preclude use of a fabric filter baghouse. The energy requirements needed for operation of an electrostatic precipitator would be significant and represent an adverse energy impact.

Environmental Impacts

There are no major environmental issues that would preclude the use of a fabric filter baghouse or dry ESP. Solid waste materials collected by the fabric filter baghouses and dry ESPs would be disposed of in accordance with State and Federal regulations. WESPs would also create a liquid waste stream.

Economic Impacts

Due to the inherently low amount of PM emissions generated from light distillate fuel oil combustion compared to the significant annualized costs of PM control technologies, cost effectiveness for a fabric filter baghouse or an ESP for an auxiliary boiler would be significantly higher than $10,000/ton, and not cost effective. Therefore, 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

A summary of recent PM BACT evaluations conducted for similar projects can be found in Table 4-12 below. BACT for PM emissions is proposed as use of low sulfur distillate fuel oil with an emission limit of 0.02 lb/MMBtu total PM/PM_{10}. This level of control and emission limit has been proposed as BACT on recent similar projects.

Table 4-12 RBLC Listings for PM Emissions from Distillate Oil Boilers Up to 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit unit
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILLARY BOILER	175	MMBTU/H	LOW ASH FUEL	0.0071	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	LOW ASH FUEL	0.0071	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.01	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	GOOD COMBUSTION PRACTICES.	0.011	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	BAGHOUSE	0.02	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.02	LB/MMBTU
ALABAMA POWER COMPANY	AL	AND -X002	12/17/1997	BOILER, FUEL OIL (NEW/USED)	190	MMBTU/H	NONE INDICATED	0.02	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	GOOD COMBUSTION PRACTICES.	0.022	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	COMBUSTION PRACTICES	0.03	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES.	0.05	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.05	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.06	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	HAS A NOX PREDICTIVE EMISSION	0.061	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	OF THE TIME. BOILERS ARE LIMITED	0.061	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES.	0.063	LB/MMBTU
TECO-POLK POWER STATION/MULBERRY	FL	PSD-FL-194	12/23/2002	BOILER, NO 2 FUEL OIL	120	MMBTU/H	NONE INDICATED	0.1	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 6 FUEL OIL	238	MMBTU/H	BAGHOUSE	0.125	LB/MMBTU
ALABAMA POWER COMPANY	AL	AND -X002	12/17/1997	BOILER, FUEL OIL (NEW/USED)	190	MMBTU/H	NONE INDICATED	0.15	LB/MMBTU
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	01-4	10/13/2004	BOILER, OIL-FIRED	192	MMBTU/H	NONE INDICATED	0.5	LB/MMBTU
OKEELANTA CORPORATION SUGAR MILL	FL	PSD-FL-169A	3/31/2003	BOILER, FUEL OIL	211	MMBTU/H	SULFUR (0.05% S BY WT) DISTILLATE	-	-

Prepared by: JDC 1/10/08
Checked by: JDF 1/10/08

4.4.2 BACT Demonstration for NOx Emissions from the Auxiliary Boiler

NO_X is a by-product of the combustion process and generally refers to both NO and NO_2. NO_X is formed by the oxidation of nitrogen contained in the fuel are oxidized 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 to form thermal NO_X. Temperature, residence time, excess air and nitrogen availability all impact the generation of NO_X.

Step 1 – Identify All Control Technologies

Combustion Controls

The use of combustion controls for NO_X emissions would be a lower pollutant emitting process, through managing the combustion process through the use of low NO_X burners to optimize the combustion process and reduce the generation of NO_X emissions. 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.

Add-On Controls

The use of add on controls for NO_X control is discussed thoroughly in section 4.1. The potential add on controls for the auxiliary boiler include:

- Low NO_X Burners (already discussed in the combustion controls section)
- Selective Catalytic reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- SCONOx
- Flue Gas Recirculation (FGR)

Step 2 – Eliminate Technically Infeasible Options

The use of add-on technology for control of NO_X emissions from the auxiliary boiler unit is not technically feasible. Use of add-on controls such as SCR, SNCR, or SCONOx has not been demonstrated in practice for control of NO_X emissions from auxiliary boilers. These controls require steady state operations, which do not occur for units that are utilized for minimized timer periods such as auxiliary boilers. Combustion controls, such as the proper combustion chamber with low NO_X burners in conjunction with flue gas recirculation are demonstrated and proven techniques for the reduction of NO_X emissions. Combustion controls are considered a demonstrated technology for auxiliary boiler NO_X emissions controls, and therefore considered technically feasible under the BACT evaluation process.

Step 3 – Rank Remaining Technically Feasible Control Options

Combustion controls are 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. Therefore, there are no energy or environmental impacts associated with the implementation of combustion controls. Since combustion controls are now a standard part of the design process of a boiler, there are no economic impacts associated with the implementation of combustion controls.

Step 4 – Evaluate Remaining Control Technologies

There are no energy, environmental, or economic impacts associated with the use of combustion controls which precludes the use of combustion controls as BACT for NO_X emissions for an auxiliary boiler.

Step 5 – Selection of BACT

A summary of recent NO_X BACT evaluations conducted for similar projects can be found in Table 4-13 below. The proposed BACT for NO_X emissions was chosen as the implementation of combustion controls including low NO_X burners and flue gas recirculation with an emission limit of 0.1 lb/MMBtu. This level of emissions has been chosen as BACT on recent similar projects. Facilities with lower emission limits are utilizing a different grade of fuel, or have not yet been demonstrated in practice.

Table 4-13 RBLC Listings for Nitrogen Oxide (NO_X) Emissions from Distillate Oil Boilers Up To 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILLARY BOILER	175	MMBTU/H	LOW ASH FUEL	0.1	LB/MMBTU
TECO-POLK POWER STATION/MULBERRY	FL	PSD-FL-194	12/23/2002	BOILER NO 2 FUEL OIL	120	MMBTU/H	LOW-NOX BURNERS	0.1	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	LOW NOX BURNER. EACH BURNER HAS A NOX PREDICTIVE EMISSION MONITORING SYSTEM.	0.12	LB/MMBTU
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	ND	PTC98002	7/9/1998	BOILER, KEWAUNEE	13	MMBTU/H	NONE INDICATED	0.14	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION PRACTICES	0.14	LB/MMBTU
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILERS, AUXILIARY, 2, FUEL OIL	117	MMBTU/H	LOW NOX BURNERS, HOURLY OPERATION LIMIT	0.169	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.2	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU/H	GOOD COMBUSTION PRACTICES.	0.2	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU/H	LOW ASH FUEL	0.4	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	BAGHOUSE	0.7	LB/MMBTU

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4.4.3 BACT Demonstration for Carbon Monoxide (CO) Emissions from the Auxiliary Boiler

CO is a by-product of the incomplete combustion of carbon in the fuel source, in this case coal, in the combustion unit in use. 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 NO_X emissions through thermal formation of NO_X emissions. Therefore, any evaluation of the reduction of CO emissions needs to take into account the potential secondary impacts in reductions of CO emissions.

Step 1 – Identify All Control Technologies

Combustion Controls

The use of combustion controls for CO emissions would be a lower pollutant emitting process, through managing the combustion process to optimize the combustion process and reduce the generation of CO emissions. 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. CO 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 CO 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 CO emissions, it would likely increase the formation of thermal NO_X, and increase overall NO_X emissions.

Add-On Controls

No effective add-on controls currently exist for CO emissions from a boiler. Use of control technologies such as afterburners would use large quantities of natural gas and simply covert CO to CO_2. Use of afterburners, and other control devices such as catalytic oxidation or flares, have not been demonstrated in practice in auxiliary boiler units. Any such control devices would lead to negative secondary environmental impacts (more NO_X emissions).

Step 2 – Eliminate Technically Infeasible Options

As discussed above, the use of add-on controls for control of CO emissions for the auxiliary boiler unit is not technically feasible. Use of add-on controls such as flares, afterburners, catalytic oxidation, and external thermal oxidation have 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 – Rank Remaining Technically Feasible Control Options

Combustion controls are the only feasible technology for control of CO emissions. Combustion controls are designed to optimize the emissions of CO (and consequently NO_X) from an auxiliary boiler. Therefore, there are no energy or environmental impacts associated with the implementation of combustion controls. Since combustion controls are now a standard part of the design process of a boiler, there are no economic impacts associated with the implementation of combustion controls.

Step 4 – Evaluate Remaining Control Technologies

There are no energy, environmental, or economic impacts associated with the use of combustion controls which precludes the use of combustion controls as BACT for CO emissions for an auxiliary boiler.

Step 5 – Selection of BACT

A summary of recent CO BACT evaluations conducted for similar projects can be found in Table 4-14 below. BACT for CO emissions is chosen as the implementation of combustion controls and an emission limit of 0.04 lb/MMBtu. This level of BACT is comparable to the level chosen for recent similar projects.

Table 4-14 RBLC Listings for Carbon Monoxide (CO) Emissions from Distillate Oil Boilers Up To 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Unit	Control Description	Emissions Limit	Emission Limit Unit
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 6 FUEL OIL	238	MMBTU/H	NONE LISTED	0.034	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	COMBINED)	35.5	MMBTU/H	NONE LISTED	0.034	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	NONE LISTED	0.036	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 2 (NO. 2 OIL)	230.8	MMBTU/H	NONE LISTED	0.036	LB/MMBTU
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	ND	PTC98002	7/9/1998	BOILER, NEBRASKA, BACKUP OIL	28	MMBTU/H	NONE LISTED	0.036	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILLARY BOILER	175	MMBTU/H	COMBUSTION CONTROLS	0.036	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	COMBUSTION CONTROLS	0.036	LB/MMBTU
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	ND	PTC98002	7/9/1998	BOILER, KEWAUNEE	13	MMBTU/H	NONE LISTED	0.038	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 4 (NO. 2 OIL)	204.2	MMBTU/H	NONE LISTED	0.04	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (NO. 2 OIL)	84.4	MMBTU/H	NONE LISTED	0.04	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 3 (NO. 2 OIL)	241.6	MMBTU/H	NONE LISTED	0.04	LB/MMBTU
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	ND	PTC98002	7/9/1998	BOILER, TRANE MURRAY, BACKUP OIL	189	MMBTU/H	NONE LISTED	0.08	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	GOOD COMBUSTION PRACTICE	0.1	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES.	0.105	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	GOOD COMBUSTION PRACTICES.	0.105	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	GOOD COMBUSTION PRACTICE	0.12	LB/MMBTU
ALABAMA POWER COMPANY	AL	AND -X002	12/17/1997	BOILER, FUEL OIL (NEW/USED)	190	MMBTU/H	NONE LISTED	0.18	LB/MMBTU
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-01-4	10/13/2004	BOILER, OIL-FIRED	192	MMBTU/H	GOOD COMBUSTION PRACTICES	0.2	LB/MMBTU
VCU EAST PLANT	VA	50126	37711	BOILER - OIL OR GAS	150	MMBTU	GOOD COMBUSTION PRACTICES.	0.263	LB/MMBTU

Prepared by: <u>JDC 1/10/08</u>
Checked by: <u>JDF 1/10/08</u>

4.4.4 BACT Demonstration for VOC Emissions from the Auxiliary Boiler

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.

Step 1 – Identify All Control Technologies

Combustion Controls

The use of combustion controls for VOC emissions would be a lower pollutant emitting process, through managing the combustion process to optimize the combustion process and reduce the generation of VOC emissions. 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 NO_X, and increase overall NO_X emissions.

Add-On Controls

No effective add-on controls currently exist for VOC emissions from a boiler. Use of afterburners, and other control devices such as catalytic oxidation or flares, have not been demonstrated in practice in boiler units. Any such control devices would lead to negative secondary environmental impacts. The use of combustion controls is widely recognized as BACT for VOC emissions for boilers.

Step 2 – Eliminate Technically Infeasible Options

As discussed above, the use of add-on controls for control of VOC emissions for the PC boiler units is not technically feasible. Use of add-on controls such as flares, afterburners, catalytic oxidation, and thermal oxidation have not been demonstrated in practice for control of VOC emissions from auxiliary boiler units. 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 – Rank Remaining Technically Feasible Control Options

Combustion controls are the only feasible technology for control of VOC emissions. Combustion controls are designed to optimize the emissions of VOC (and consequently NO_X) from a PC fired boiler. Therefore, there are no energy or environmental impacts associated with the implementation of combustion controls. Since combustion controls are now a standard part of the design process of a boiler, there are no economic impacts associated with the implementation of combustion controls.

Step 4 – Evaluate Remaining Control Technologies

There are no energy, environmental, or economic impacts associated with the use of combustion controls which precludes the use of combustion controls as BACT for VOC emissions for an auxiliary boiler unit.

Step 5 – Selection of BACT

A summary of recent VOC BACT evaluations conducted for similar projects can be found in Table 4-15 below. BACT for VOC emissions is proposed as the implementation of combustion controls and an emission limit of 0.003 lb/MMBtu. This level of BACT is comparable to the level chosen for recent similar projects.

Table 4-15 RBLC Listings for Volatile Organic Compound (VOC) Emissions from Distillate Oil Boilers Up To 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-01-4	10/13/2004	BOILER, OIL-FIRED	192	MMBTU/H	GOOD COMBUSTION PRACTICES	0.02	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	GOOD COMBUSTION PRACTICES	0.005	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	NATURAL GAS LIMIT AND DISTILLATE FUEL OIL LIMIT.	0.03	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILLARY BOILER	175	MMBTU/H	COMBUSTION CONTROLS	0.0015	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 6 FUEL OIL	238	MMBTU/H	NONE INDICATED	0.005	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	NONE INDICATED	0.0016	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES.	0.014	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	GOOD COMBUSTION PRACTICES.	0.014	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	GOOD COMBUSTION	0.014	LB/MMBTU
ALABAMA POWER COMPANY	AL	108-0018-X001 AND -X002	12/17/1997	BOILER, FUEL OIL (NEW/USED)	190	MMBTU/H	NONE INDICATED	0.01	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	COMBUSTION CONTROLS	0.001	LB/MMBTU

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Checked by: JDF 1/10/08

4.4.5 BACT Demonstration for Sulfur Dioxide (SO_2) Emissions from the Auxiliary Boiler

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. Since the auxiliary boiler will be fired on light distillate oil (diesel fuel), the sulfur content of the fuel will be easily controlled.

Step 1 – Identify All Control Technologies

Fuel Selection

Firing of lower sulfur fuel is a common lower emission process/practice to lower SO2 emissions.

Add-On Controls

Add on controls for SO_2 are generally post combustion and are similar to those discussed for the PC boiler. The add-on controls generally include wets scrubbers, dry scrubbers, sorbent injection, limestone injection, and activated carbon injection.

Step 2 – Eliminate Technically Infeasible Options

Each of the identified controls was reviewed and the infeasible options identified. For the purposes of the auxiliary boiler, only the low sulfur fuel, dry scrubbers, and wet scrubbers were identified as technically feasible. Any control devices added to this unit would be ineffective due to the short duration that they would be used.

Step 3 – Rank Remaining Technically Feasible Control Options

The RBLC identifies low-sulfur fuel as the most stringent limit for an auxiliary boiler combusting fuel oil. The combination of the low duty cycle, 10 percent, in conjunction with the placement and configuration of the auxiliary boiler at a power plant have generally eliminated consideration of emission controls. Since the primary purpose of the auxiliary boiler is for start up and shut downs of the PC boiler, it operational schedule generally precludes the use of onsite control systems.

Step 4 – Evaluate Remaining Control Technologies

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

Step 5 – Selection of BACT

A summary of recent SO_2 BACT evaluations conducted for similar projects can be found in Table 4-16 below. Based on the preceding analysis, the proposed BACT for SO_2 emissions is combustion of low sulfur fuel. Compliance with this limitation will be through fuel certification. The emission limit proposed as BACT would be 0.05 lb/MMBtu.

Table 4-16 RBLC Listings for Sulfur Dioxide (SO_2) Emissions from Distillate Oil Boilers Up To 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, AUXILIARY, # 1 & #2	117	MMBTU/H	USE OF LOW SULFUR FUEL OIL (0.05% S), LIMIT ON HOURS OF OPERATION.	0.055	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	0.52	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	0.53	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	FUEL SULFUR LIMIT: < 0.5% S BY WT	0.52	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 6 FUEL OIL	238	MMBTU/H	NONE INDICATED	1.6	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	NONE INDICATED	1.6	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	FUEL SULFUR LIMITS: < 0.05% S BY WEIGHT	0.8	LB/MMBTU
PENN SPECIALTY CHEMICALS	TN	0274-04B	1/19/2001	BOILER, FUEL OIL, 4-C	250	MMBTU/H	CEMS/OPERATIONAL CONTROLS	0.1	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	LOW S FUELS: < .05% BY WT S	0.052	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILLARY BOILER	175	MMBTU/H	LOW SULFUR FUEL OIL	0.051	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	SULFUR CONTENT < 0.05% S BY WT.	0.051	LB/MMBTU
OKEELANTA CORPORATION SUGAR MILL	FL	PSD-FL-169A	10/29/2001	BOILER, FUEL OIL	211	MMBTU/H	SULFUR (0.05% S BY WT)	0.054	LB/MMBTU
PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	3P (SEE NOTES)	3/5/2001	UTILITY BOILER #2 (FUEL OIL)	183	MMBTU/H	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.	0.217	LB/MMBTU
PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	3P (SEE NOTES)	3/5/2001	UTILITY BOILER #50-1 (FUEL OIL)	225	MMBTU/H	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.	0.217	LB/MMBTU

Prepared by: JDC 1/10/08
Checked by: JDF 1/10/08

4.4.6 BACT Demonstration for Sulfuric Acid Mist (H_2SO_4) Emissions from the Auxiliary Boiler

SAM is formed by the oxidation of a portion of the SO_2 in the stack gases to SO_3, which then reacts with water vapor in the flue gas to form H_2SO_4. Since the basis of the formation of SAM is SO_2 emissions, then the SO_2 BACT should also be considered BACT for SAM.

Step 1 – Identify All Control Technologies

Fuel Selection

Firing of lower sulfur fuel is a common lower emission process/practice to lower H_2SO_4 emissions.

Add-On Controls

Add on controls for SO_2 are generally post combustion and are similar to those discussed for the PC boiler. The add-on controls generally include wets scrubbers, dry scrubbers, sorbent injection, limestone injection, and activated carbon injection.

Step 2 – Eliminate Technically Infeasible Options

Each of the identified controls were reviewed and the infeasible options identified. For the purposes of the auxiliary boiler, only the low sulfur fuel, dry scrubbers, and wet scrubbers were identified as technically feasible.

Step 3 – Rank Remaining Technically Feasible Control Options

The RBLC identifies low-sulfur fuel as the most stringent limit for an auxiliary boiler combusting fuel oil. The combination of the low duty cycle, 10 percent, in conjunction with the placement and configuration of the auxiliary boiler at a power plant have generally eliminated consideration of emission controls. Since the primary purpose of the auxiliary boiler is for start up and shut downs of the PC boiler, it operational schedule generally precludes the use of onsite control systems.

Step 4 – Evaluate Remaining Control Technologies

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

Step 5 – Selection of BACT

A summary of recent H_2SO_4 BACT evaluations conducted for similar projects can be found in Table 4-17 below. Based on the preceding analysis, the proposed BACT for H_2SO_4 emissions is combustion of low sulfur fuel. Compliance with this limitation will be through fuel certification. This level of BACT has been proposed on recent similar projects.

Table 4-17 RBLC Listings for Sulfuric Acid Mist (H_2SO_4) Emissions from Distillate Oil Boilers Up To 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Unit	Control Description	Emissions Limit	Emission Limit Unit
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILLARY BOILER	175	MMBTU/H	LOW SULFUR FUEL OIL	0.0008	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	LOW SULFUR FUEL OIL	0.0008	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	FIRE PUMP	2.7	MMBTU/H	LIMITED TO BURN DIESEL 150 H/YR.	0.0017	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	DISTILLATE FUEL OIL LIMIT.	0.0025	LB/MMBTU

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4.5 Diesel Engine Generator and Fire Water Pump

The facility plans to install and operate a diesel fired emergency backup generator and diesel fired emergency fire pump. The two engines will operate only during emergencies and/or maintenance cycles. The facility plans on limiting the operating hours of these engines to 500 hours per year for each engine. Typical maintenance operations range from 4 to 8 hours per month.

Step 1 – Identify All Control Technologies

Combustion is a thermal oxidation process which produces emissions as a byproduct of fuel combustion. Combustion of diesel fuel produces emissions of VOC, CO, SO_2, NO_x, PM, H_2SO_4 and trace amounts of Fluorides and Lead. Categories of potential control technologies to reduce these emissions were identified as: 1) prevent the formation of the emissions, 2) reduce the formation of the pollutant as low as technologically possible, or 3) treat the emissions once the pollutants have been formed. The identified technologies include:

Lower Emitting Process Practices

The process of controlling combustion conditions to reduce the formation of VOC, CO**,** NO_x, and PM is the generally accepted method for controlling these pollutants. Emissions of these pollutants are regulated under the New Source Performance Standard (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)/ These options were described in section 4.1 of this report. 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 RBLC.

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 diesel fuel has been developed to further reduce sulfur emission from diesel fired engines. As an added bonus, the low sulfur fuel has also been identified as being a low ash fuel, which also reduces emissions of PM 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, we have identified that add on controls are not a feasible option for this type of operation. The add on control unit are considered infeasible based on the installation cost and the operation and maintenance costs associated with limited operation.

Step 3 – Rank Remaining Technically Feasible Control Options

Good combustion practices are considered the only feasible control method for controlling emissions of VOC, CO, and NO_x,. Combustion of low sulfur fuel is the s emissions of SO_2, H_2SO_4 and PM is the only technically feasible control technology.

Step 4 – Evaluate Remaining Control Technologies

Good combustion practices are the most effective strategy for controlling emissions of VOC, CO, and NO_x,. Combustion of low sulfur fuel for reducing the emissions of SO_2, H_2SO_4 and PM is the only technically feasible control technology. There are no energy, environmental or economic impacts that would preclude the use of good combustion controls or low sulfur fuel.

Step 5 – Selection of BACT

The proposed BACT for the emergency backup generator and the emergency fire pump will be the utilization of good combustion controls and the use of low sulfur fuels. The emergency backup generator and the emergency fire pump engine will comply with the emission limitations contained in 40 CFR 60 Subpart IIII. Additionally, the facility proposes to use low sulfur diesel fuel. Compliance will be demonstrated with these limits by manufacturer’s certification and fuel certification.

4.6 Cooling Towers

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 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 (emission points S-2 through S-35). Mineral matter present in the water droplets released in the drift is considered PM emissions.

4.6.1 BACT Demonstration for PM Emissions from the Cooling Towers

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 becomes particulate matter.

The only available control method available for wet cooling towers are 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 proposed BACT for this project is the use of ultra high efficiency drift eliminators with an efficiency of 0.0005 percent. The proposed method of compliance for the drift eliminators is by use of a manufacturer's guarantee and analysis of the quality of the Total Dissolved Solids (TDS) in the cooling tower makeup water, limited to 3300 mg/L. This drift limit is consistent with recent BACT evaluations for other power production facilities, and the RBLC database confirms BACT levels of 0.0005 percent. A review of the literature and the RBLC database indicate that this is the highest level of control at this time as indicated in Table 4-18.

Table 4-18 RBLC Listings for Cooling Tower Drift

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
ADM CORN PROCESSING - CEDAR RAPIDS	IA	57-01-080	6/29/2007	INDUSTRIAL COOLING TOWER	150000	GALLON/MIN	DRIFT ELIMINATORS	0.0005	% DRIFT RATE
LA PAZ GENERATING FACILITY	AZ	1001743	9/4/2003	MECHANICAL DRAFT COOLING TOWERS FOR GE TURBINES	173870	GALLON/MIN	DRIFT ELIMINATORS	0.0005	% BY VOL
LA PAZ GENERATING FACILITY	AZ	1001743	9/4/2003	MECHANICAL DRAFT COOLING TOWERS FOR SIEMENS TURBINES	141400	GALLON/MIN	DRIFT ELIMINATORS	0.0005	% BY VOL
SPIRITWOOD STATION	ND	PTC07026	9/14/2007	COOLING TOWER	80000	GALLON/MIN	DRIFT ELIMINATOR	0.0005	% COOLING WATER FLOW
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	COOLING TOWER	UNKNOWN		DRIFT ELIMINATORS	0.0005	% DRIFT LOSS
TRIGEN-NASSAU ENERGY CORPORATION	NY	1-2820-01015/00009	3/31/2005	COOLING TOWER			NONE INDICATED	0.0005	% DRIFT
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COOLING TOWER, F80 (07-A-979P)	50000	GALLON/MIN	DEMISTER	0.0005	% DRIFT LOSS
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COOLING TOWER, F80 (07-A-979P)	50000	GALLON/MIN	DEMISTER	0.0005	% DRIFT LOSS
ADM CORN PROCESSING - CEDAR RAPIDS	IA	57-01-080	6/29/2007	INDUSTRIAL COOLING TOWER	150000	GALLON/MIN	DRIFT ELIMINATORS	0.0005	% EFF. DRIFT ELIMIN
COMANCHE STATION	CO	04UNITPB1015	38538	COOLING TOWER	140650	GALLON/MIN	ACHIEVE 0.0005 % DRIFT OR	0.0005	% DRIFT RATE
COMANCHE STATION	CO	04UNITPB1015	38538	COOLING TOWER	140650	GALLON/MIN	ACHIEVE 0.0005% DRIFT OR	0.0005	% DRIFT RATE
DICKERSON	MD	CPCN CASE NO. 8888	11/5/2004	COOLING TOWER	10	CELLS	MIST ELIMINATORS	0.001	% DRIFT RATE
HORSESHOE ENERGY PROJECT	OK	2001-156-C PSD	2/12/2002	COOLING TOWERS	111438	GALLON/MIN	DESIGN	0.001	% DRIFT
GENOVA ARKANSAS I, LLC	AR	2009-AOP-R0	8/23/2002	COOLING TOWER	11.4	MMGAL/H	DRIFT ELIMINATORS	0.001	% DRIFT LOSS
DARRINGTON ENERGY COGENERATION POWER PLANT	WA	PSD 03-04	38394	COOLING TOWER			ELIMINATORS WITH DRIFT	0.001	% DRIFT RATE
BP CHERRY POINT COGENERATION PROJECT	WA	EFSEC/2002-01	38363	COOLING TOWER			ELIMINATORS WITH DRIFT	0.001	% DRIFT RATE
BATON ROUGE REFINERY	LA	PSD-LA-667(M-1)	2/18/2004	COOLING TOWERS			DRIFT ELIMINATOR SYSTEM	0.003	% DRIFT
PLAQUEMINE COGENERATION FACILITY	LA	PSD-LA-659	12/26/2001	COOLING TOWER	0.01	% DRIFT RATE	PRACTICES	0.005	% DRIFT RATE
GARYVILLE REFINERY	LA	PSD-LA-719	12/27/2006	HYDROGEN PLANT COOLING TOWER (53-08)			ELIMINATORS	0.005	% DRIFT RATE
ROCKPORT WORKS	IN	147-6713-00041	2/13/1997	COOLING TOWERS (2), NON-CONTACT			DRIFT ELIMINATORS	0.005	% DRIFT
AUBURN NUGGET	IN	033-19475-00092	5/31/2005	COOLING TOWER	23450	GALLON/MIN	NONE INDICATED	0.005	% OF THROUGH PUT
NUCOR STEEL	NC	08680T09	11/23/2004	COOLING TOWERS			0.008 PERCENT DRIFT LOSS	0.008	% DRIFT RATE
NUCOR STEEL	NC	08680T09	38314	COOLING TOWERS			0.008 PERCENT DRIFT LOSS	0.008	% DRIFT RATE
ST. CHARLES REFINERY	LA	PSD-LA-619(M-2)	39121	COOLING TOWERS (2004-6, 2005-42, & 2005-43)			DRIFT ELIMINATORS	-	-
KELSON RIDGE	MD	CPCN CASE NO. 8843	37161	COOLING TOWERS			MIST ELIMINATORS	-	-
NUCOR STEEL	IN	107-12143-00038	36910	COOLING TOWER SYSTEM	12000	GALLON/MIN	NO NUMERICAL LIMIT	-	-

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4.7 Material Handling and Storage Facilities

Particulate emissions 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; and haul roads. The particulate sources can be grouped into the following categories: transfer points, storage piles, material processing and haul roads. The permit application contains detailed descriptions of the material handling emissions points and associated emissions calculations.

Step 1 – Identify All Control Technologies

Control options for potential application to the material handling and storage facilities were identified by category. The potential controls include the following:

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, use of surfactants or crusting agents)

2) **Storage Piles**
   Full Enclosure
   Partial Enclosure
   Dust Suppressions (water sprays, surfactants, crusting agents, 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

Transfer Points

Transfer points include coal railcar unloading, transfer point for PRB coal, transfer point for Illinois #6 coal, limestone railcar unloading, unloading conveyor to limestone stackhouse, fly-ash mechanical exhausters, bottom ash transfer point to storage bin, and bottom ash transfer point from bin to truck. In addition, the tripper deck, fly ash silo, the Hg sorbent silo, the SO_3 sorbent silo, the pre-treatment soda ash silo, and the pre-treatment hydrated lime silo 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 the transfer point for Illinois #6 coal because of railcar handling procedures and safety procedures. The other two (2) 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.

Storage Piles

Storage piles include an active pile for PRB coal, an active pile for Illinois #6 coal, an inactive pile for PRB coal, an inactive pile for Illinois #6 coal, an active pile for limestone and the solid materials handling operations. Seven potential control options were identified in Step 1 for control of emissions from storage pile emissions. Of the seven options identified, the full enclosure control strategy for the storage piles is not technically feasible.

Material Processing

Material processing areas on site include a coal preparation facility and a limestone preparation facility. Both processing operations are to be enclosed inside a separate building. The control option identified in Step 1, enclosing processing operations and utilizing dust suppression and/or a dust collector is technically feasible.

Haul Roads

Haul roads onsite are primarily internal roadways utilized by the facility to transport combustion byproducts to the onsite 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 – Rank Remaining Technically Feasible Control Options

Transfer Points

With the exception of 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, use of surfactants or crusting agents).

Material Processing

Since only one option was identified for onsite material processing, no ranking is required.

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 must 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 add to or removed from the piles. Dust suppression sprays are also effective during pile maintenance operations.

Particulate emissions from operations at the onsite 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 onsite storage facility. The operations and maintenance practice will be fully identified in the solid materials handling operations plan.

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. Since the facility is planning on implementing both control strategies, no additional evaluation is required.

Step 4 – Evaluate Remaining Control Technologies

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. Since the facility plans on using fully enclosed transfer points with dust controls where feasible, additional evaluation is not warranted.

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 facility will use water sprays, surfactants, seeding agents and contouring to obtain a control efficiency of 90 percent. Telescoping chutes and lowering well will also be utilized in the transfer point to further minimize emissions from storage pile operation. Covering, limiting the active cell area and other best management practices will be utilized in the onsite storage facility to reduce particulate emissions.

Material Processing

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

Haul Roads

Dust suppression techniques, including the use of water sprays, in conjunction with paving haul roads to obtain a control efficiency of 80 to 90 percent. Regular cleaning and application of water sprays will also reduce roadway dust emissions.

Step 5 – Selection of BACT

Techniques to control emissions from material handling identified herein will be utilized to reduce particulate emissions from these processes. The proposed facility will utilize a combination of enclosures, dust collectors, telescopic chutes, lowering wells, wet suppression systems, covering, crusting agents as BACT for material handling. Baghouses with flow rates greater than 1000 ACFM will have a maximum average outlet loading of 0.005 grains per dry standard cubic feet (gr/dscf).

Emissions from transfer points will be reduce by 80 to 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 best management practices. 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 stock 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 emission limit of 0.005 gr/dscf and proposed control procedures are consistent with recently permitted facilities and those contained in the RBLC database as shown in Table 4-19.

Table 4-19 RBLC Listings for Material Management Handling Sources

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
RICHARDTON PLANT	ND	4004	8/4/2004	COAL HANDLING	27	T/H	BAGHOUSE	0.004	GR/DSCF
ENERGY SERVICES OF MANITOWOC	WI	00-RV-092	6/26/2001	FUEL HANDLING			PULSE-JET BAGHOUSES, ENCL	0.004	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL & FLUX UNLOADING	4000000	DSCF	FF	0.005	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL & FLUX UNLOADING	4000000	DSCF	FF	0.005	GR/DSCF
UNIVERSITY OF NORTHERN IOWA	IA	02-111	5/3/2007	COAL SYSTEM - BUNKER #3 SILO	27.4	lbs/hr	BAGHOUSE	0.005	GR/DSCF
UNIVERSITY OF NORTHERN IOWA	IA	02-111	5/3/2007	COAL SYSTEM - BUNKER #3 SILO	27.4	lbs/hr	BAGHOUSE	0.005	GR/DSCF
GASCOYNE GENERATING STATION	ND	PTC 05005	6/3/2005	COAL HANDLING	400	T/H	BAGHOUSES	0.005	GR/DSCF
SPIRITWOOD STATION	ND	PTC07026	9/14/2007	COAL HANDLING	85.3	T/H	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	GASIFIER COAL FEED BINS, S14 (07-A-959P)	15	tons	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COAL STORAGE SILOS, S15 (07-A-960P)	5000	tons	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COAL STORAGE RECLAIM SILO, S16 (07-A-961P)	5000	tons	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	GASIFIER COAL FEED BINS, S14 (07-A-959P)	15	tons	BAGHOSUE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COAL STORAGE SILOS, S15 (07-A-960P)	5000	tons	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COAL STORAGE RECLAIM SILO, S16 (07-A-961P)	5000	tons	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	ROTARY CAR DUMPER	3500	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER CONVEYING BAY	1800	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER HOUSE 2	3500	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER HOUSE 4	3600	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	SILOS	900	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	ROTARY CAR DUMPER	3500	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER CONVEYING BAY	1800	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER HOUSE 2	3500	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER HOUSE 4	3600	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	SILOS	900	TONS/HR	BAGHOUSE	0.005	GR/DSCF
AUBURN NUGGET	IN	033-19475-00092	5/31/2005	COAL CAR UNLOADING	165	T/H	BAGHOUSE	0.0052	GR/DSCF
WYGEN 2	WY	CT-3030	9/25/2002	COAL HANDLING EQUIPMENT			FABRIC FILTER	0.009	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL PULVERIZER #1	36	MMBTU/H	FF	0.01	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL PULVERIZER #2	9	MMBTU/H	FF	0.01	GR/DSCF
IRON DYNAMICS, INC. (IDI)	IN	033-19160-00076	4/13/2005	COAL DRYER	25	mmbtu/h	BAGHOUSE	0.01	GR/DSCF
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	SILO, BOILER, PLANT COAL	8500	SCFM	8500 SCFM BAGHOUSE	0.01	GR/DCSF
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	DUMP POCKET, COAL	3000	SCFM	BAGHOUSE	0.01	GR/DSCF
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	SILO, COAL	6000	SCFM	BAGHOUSE	0.01	GR/DSCF
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	CRUSHER, CONE, SECONDARY COAL	6000	SCFM	6000 SCFM BAGHOUSE	0.01	GR/DSCF
AUBURN NUGGET	IN	033-19475-00092	5/31/2005	COAL DRYERS	33	T (COAL)/H	BAGHOUSE	0.01	GR/DSCF
WESTERN GREENBRIER CO-GENERATION, LLC	WV	R14-0028	4/26/2006	COAL HANDLING	300	T/H	FABRIC FILTERS	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL SURGE BIN TOP (2)	400	T/H	FABRIC FILTER	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL TUNNEL TO COAL STACKER	400	T/H	FABRIC FILTER	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL TRANSFER	400	T/H	FABRIC FILTER	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL DRYER - FK PUMP	20	T/H	FABRIC FILTER	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL HOPPER TO CONVEYOR	400	T/H	FABRIC FILTER	0.01	GR/DSCF
LONE STAR INDUSTRIES, INC.	IN	133-10159	4/16/1999	CEMENT MANUFACTURING, COAL MILL	40	T/YR	FABRIC FILTER	0.01	GR/DSCF
SUWANNEE AMERICAN CEMENT COMPANY, INC.	FL	1210465-001-AC	6/1/2000	COAL MILL			BAGHOUSE	0.01	GR/DSCF
HUGO GENERATING STA	OK	97-058-C M-2 PSD	2/9/2007	MATERIAL HANDLING			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
TS POWER PLANT	NV	AP4911-1349	5/5/2005	COAL HANDLING OPERATIONS			FABRIC FILTER DUST COLLECIT	0.01	GR/DSCF

Table 4-19 RBLC Listings for Material Management Handling Sources (Continued)

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SYSTEM 1 - NEW RECLAIM TUNNEL EXIT, #34 (P30, S30)			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	P41, S41, SYSTEM 2 - NEW JUNCTION HOUSE 2, #31 (13)			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	P42, S42, SYSTEM 3 - NEW JUNCTION HOUSE 3, #32			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	P43, S43, SYSTEM 4 - UNIT 4 SILO FILL SYSTEM #7			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
SUWANNEE AMERICAN CEMENT COMPANY, INC.	FL	1210465-001-AC	6/1/2000	COAL MILL			BAGHOUSE	0.01	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL PULVERIZER #1	36	MMBTU/H	FF	0.015	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL PULVERIZER #2	9	MMBTU/H	FF	0.015	GR/DSCF
AUBURN NUGGET	IN	033-19475-00092	5/31/2005	COAL DRYERS	33	T (COAL)/H	BAGHOUSE	0.015	GR/DSCF
ARKANSAS LIME COMPANY	AR	0045-AOP-R3	8/30/2005	COAL/COKE BIN VENT, SN-33Q #3			DUST COLLECTOR	0.015	GR/DSCF
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	P65, S65, P66, S66; PAC TRUCK UNLOADING, PAC SILO LOADING			FABRIC FILTER BAGHOUSE	0.02	GR/DSCF
MANITOWOC PUBLIC UTILITIES	WI	02-RV-147	12/3/2003	SOLID FUEL STORAGE SILO (P12 / S12)			BAGHOUSE	0.02	GR/DSCF
MANITOWOC PUBLIC UTILITIES	WI	02-RV-147	12/3/2003	ASH STORAGE SILO (P14, S14)			BAGHOUSE	0.02	GR/DSCF

Prepared by: JDC 1/10/08
Checked by: JDF 1/10/08

4.8 Storage Tanks

The facility will have three storage tanks used for storage of No. 2 distillate fuel oil. One (1) of these storage tanks will be a 350,000 gallon tank used for storage of No. 2 distillate fuel oil to be used in the main facility boiler and auxiliary boiler during startup and shutdown operations. Another of these storage tanks will be a 750 gallon tank used for storage of No. 2 distillate fuel oil to be used as necessary for the emergency diesel generator. Also, the final storage tank will be a 250 gallon tank used for storage of No 2 distillate fuel oil to be used as necessary in the facility emergency fire pump. The vapor pressure of No. 2 distillate fuel oil is very low (< 0.01 psia), so the VOC emissions from these tanks are minimal. At this low vapor pressure no control device is economically viable due to the very low rate of loss. Based on use of the USEPA TANKS Program (version 4.0.9d), used for estimation of emissions of organic emissions from storage tanks, the total VOC emission from all storage tanks will be less than 200 lb/yr.

Work practices at the facility will be implemented to minimize VOC emissions from the facility storage tanks as much as possible. The proposed BACT for the storage tanks is use of conservation vent valves where applicable and best management practices to minimize emissions.

4.9 Opacity

Control methodologies established as BACT for this evaluation have also been established to minimize the formation of visible emissions from facility emission points. These controls are discussed in detail in the particular BACT section for each process.

Opacity is a measurement of visible emissions, and is defined as the amount of light which is blocked by a medium, such as smoke. An opacity of 0 percent means that all light passes through the medium, and an opacity of 100 percent would mean that no light could pass through the medium. Opacity can be an indication of the concentration of pollutants being discharged from a stack. The more particles that are emitted from a stack, the more light will be blocked by the particles (medium), and a higher percent opacity will result.

The facility is proposing a 10 percent opacity limit on a six minute average for those operations not already covered by a more stringent opacity standard (i.e., NSPS Subpart OOO). Compliance with this level will be maintained by:

- Proper control device maintenance and operation

- Dust Suppression Techniques to minimize fugitive emissions of Particulate Matter (PM)

5.0 PSD AMBIENT AIR QUALITY ANALYSIS

The proposed project triggered a PSD review for PM_{10}, NO_x, CO, SO_2, VOC, Lead (Pb), Sulfuric Acid Mist (SAM) and Fluorides (as HF) as indicated in Section 3.0; therefore, an air quality modeling analysis was required for each pollutant (PSD modeling is not required for SAM, however, it is included in the air toxics analysis modeling evaluation in Section 7). Although the project triggers a PSD review for VOC, there are no modeling requirements for VOC emissions; therefore, a modeling analysis was not completed for this pollutant. Screening analyses indicated that the project will exceed the PSD Significant Impact Levels (SILs) for SO_2 while PM_{10}, NO_x, and CO concentrations will be below their corresponding levels. HF and Pb are below their significant monitoring level concentrations. Refined modeling was completed for SO_2. The results of the refined modeling analysis demonstrated that the project will not exceed either the National Ambient Air Quality Standards (NAAQS) or PSD Increment consumption levels for SO_2 and therefore will comply with the PSD air quality standards. The results of this analysis are summarized in the following sections. Electronic copies of the input and output files for the model runs are included on a disc in Exhibit D.

5.1 MODELING METHODOLOGY

The first step in air quality modeling is to run a screen model of all emission sources at the proposed facility. The screen model results for the PSD-triggered pollutants are used to determine whether the emission increases from the proposed facility will result in concentrations that exceed their respective SILs. Refined modeling will be required if significant levels are exceeded. Table 5-1 shows the SILs for PM_{10}, $PM_{2.5}$, NO_x, SO_2, and CO. Current USEPA guidelines call for $PM_{2.5}$ to be evaluated as a surrogate for PM_{10}. Currently there are no promulgated significant impact levels for $PM_{2.5}$, however, on September 21, 2007 the USEPA proposed significant impact levels for $PM_{2.5}$. This USEPA proposal includes three options for $PM_{2.5}$ SILs. As a worst case evaluation, the modeling results for $PM_{2.5}$ are being compared to the lowest of the three options. This modeling is not a requirement for the permit application under current guidelines; however, the results are being included in order to demonstrate that the plant will have an insignificant impact on $PM_{2.5}$ concentrations in the area. The screen results were also compared to the lowest of the proposed $PM_{2.5}$ significant monitoring concentrations to determine whether a review for preconstruction monitoring will be required.

Table 5-1 Significant Impact Levels and Significant Monitoring Concentrations

Pollutant	**Averaging Period**	**Significant Ambient Impact Level ($\mu g/m^3$)**	**Significant Monitoring Concentrations ($\mu g/m^3$)**
$PM_{2.5}$[1]	24-hour	1.20	-
	Annual	0.30	-
PM_{10}	24-hour	5	10
	Annual	1	-
SO_2	3-hour	25	-
	24-hour	5	13
	Annual	1	-
NO_x	Annual	1	14
CO	8-hour	500	575
	1-hour	2,000	-
Pb	Calendar Quarter	-	0.10
HF	24-hour	-	0.25

1. Lowest of the three proposed Significant Impact Levels.

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Checked by: SAK 1/17/08

The concentrations used for comparison to significant levels calculated by the screen models were the highest concentrations predicted at any receptor for all averaging periods for each modeled pollutant. In screening and refined modeling, the maximum concentration predicted by the model was resolved to within the 100-meter receptor grid spacing to obtain a true maximum (if the initial maximum receptor was not already located in the 100-meter spacing portion). The USEPA AERMOD model was used for all pollutants for all averaging periods. The latest version of AERMOD (Version 07026) was downloaded from USEPA's Support Center for Regulatory Air Models (SCRAM) Web site for use in the modeling.

The latest USEPA's Building Profile Input Program for Prime (BPIP-PRIME model -version 04274) was used to calculate flow vectors based on 36 possible wind directions in order to allow for building downwash.

A Cartesian receptor grid was used for the model runs. Receptors were spaced 100 meters apart along the fence line/patrolled property line and out to a distance of 2 kilometers from the property boundary. Receptors were spaced at 500 meters apart from 2 kilometers to 10 kilometers out from the property boundary. Figure 5-1 shows the receptors used in the PSD screen modeling. Digital Elevation Model (DEM) data obtained from the U.S. Geological Survey was used to determine receptor heights using USEPA's AERMAP (Version 06341) computer program.

As part of the project, Power4Georgians will be closing the portion of Mayview road that goes through the plant property. A letter from the Washington County Board of Commissioners to the EPD director outlining this road closure is included in Exhibit C of the permit application. With the closure of this road, this portion of the plant property will not have public access and will not therefore be included in the modeling evaluation.

The proposed project will result in a potential VOC emission increase greater than 100 tons per year; therefore, the PSD air modeling guidelines require an evaluation to determine whether preconstruction monitoring is warranted. Preconstruction monitoring of ozone can be waived in the event that representative data for the area is available. The Georgia EPD operates ozone monitors at 24 locations across the state including two sites northeast of the site in Richmond and Columbia Counties and two sites West/ Southwest of the site in Bibb County. These monitors are considered representative of the ozone levels in the area. The maximum 1-hour and 8-hour ozone monitor values for 2006 from the monitors are 0.10 ppm and 0.09 ppm for the Richmond County monitor, 0.14 ppm and 0.09 ppm for the Columbia County monitor, and 0.10 and 0.09 ppm for the closest monitor in Bibb County (Georgia Forestry Commission monitor). The only impact that VOC emissions could have on air quality is the potential creation of ozone when combined with NO_x in ambient air in the presence of sunlight. Photochemical smog is not a problem in this area of the state.

The regulatory default option and rural environment were used in the models. The Auer Method, which determines the characteristics of a modeling area, was used to confirm that the land use surrounding the proposed site in Washington County is rural, as shown in Table 5-2. Figure 5-2, a topographic map of the area surrounding the proposed plant, denotes land use within 3 kilometers.

Table 5-2 Land Use Analysis - Auer Method

Type	**Use and Structure**	**Vegetation**	**50% of Land Use? (Y/N)**
I1	**Heavy Industrial** Major chemical, steel, and fabrication industries; generally 3- to 5-story buildings with flat roofs	Grass and tree growth extremely rare. Less than 5% vegetation.	**N**
I2	**Light-moderate Industrial** Rail yards, truck depots, warehouses, industrial parks, and minor fabrications; generally 1- to 3-story buildings with flat roofs	Very limited grass; trees almost totally absent. Less than 5% vegetation.	**N**
C1	**Commercial** Office and apartment buildings and hotels; 10 stories and flat roofs	Limited grass and trees. Less than 5% vegetation.	**N**
R2	**Compact Residential** Single and some multiple family dwellings with close spacing; generally 2 stories with pitched roofs; garages (via alley) and ash pits; no driveways	Limited lawn sizes and shade trees. Less than 30% vegetation.	**N**
R3	**Compact Residential** Old multi-family dwellings with close (2-meter) lateral separation; generally 2-story, flat-roof structures; garages (via alley) and ash pits; no driveways	Limited lawn sizes and old, established shade tress. Less than 35% vegetation.	**N**
	Conclusion – Urban or Rural?		**Rural Modeling Area**

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Checked by: SAK 1/17/08

Each emission source was modeled at its maximum hourly emission rate for all modeled pollutants. Table 5-3 summarizes the emission rates and modeling parameters that were used for the on-site modeled emission sources in the screen model runs.

Figure 5-1 Aerial Photograph Showing 3-Kilometer Radius around Proposed Site

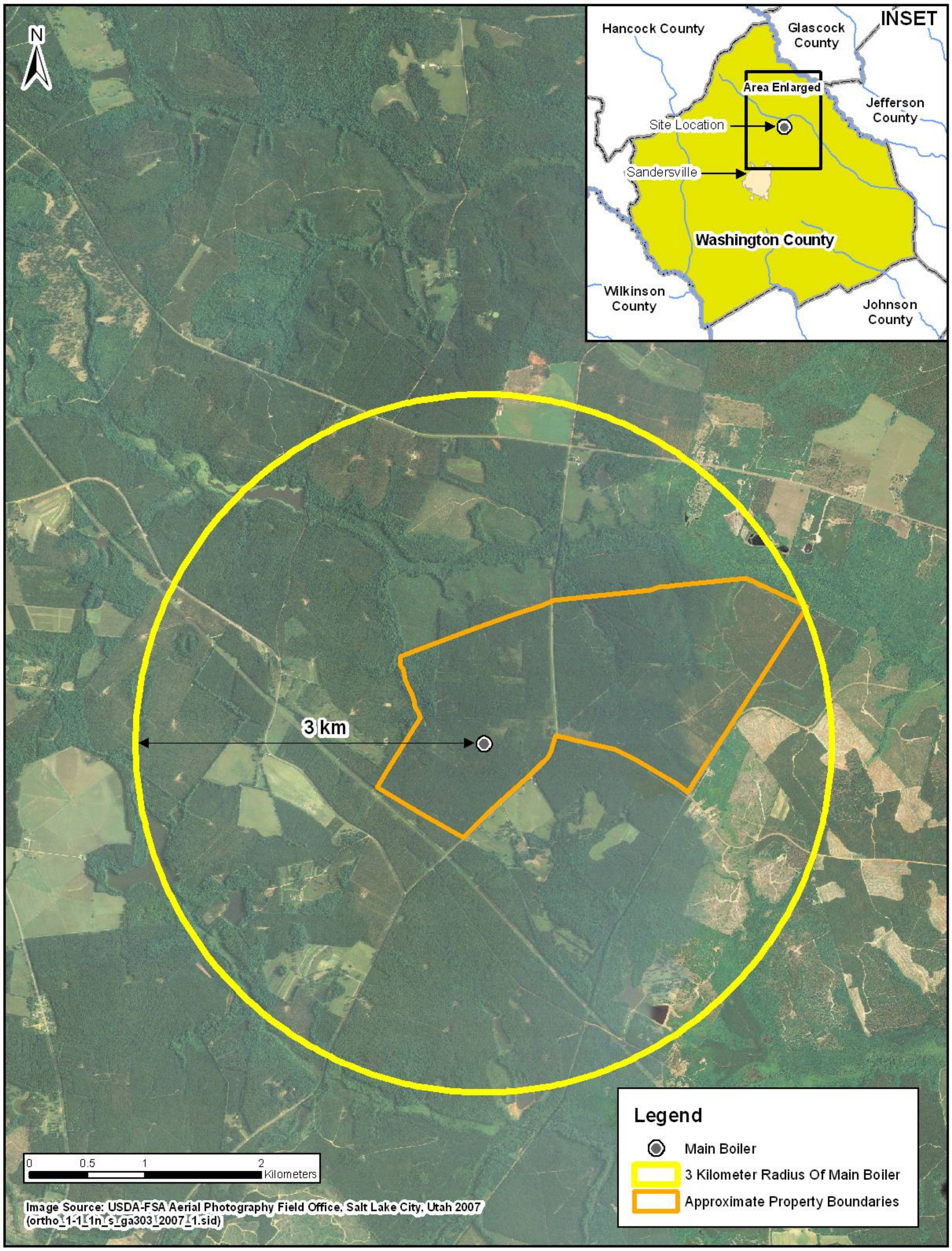
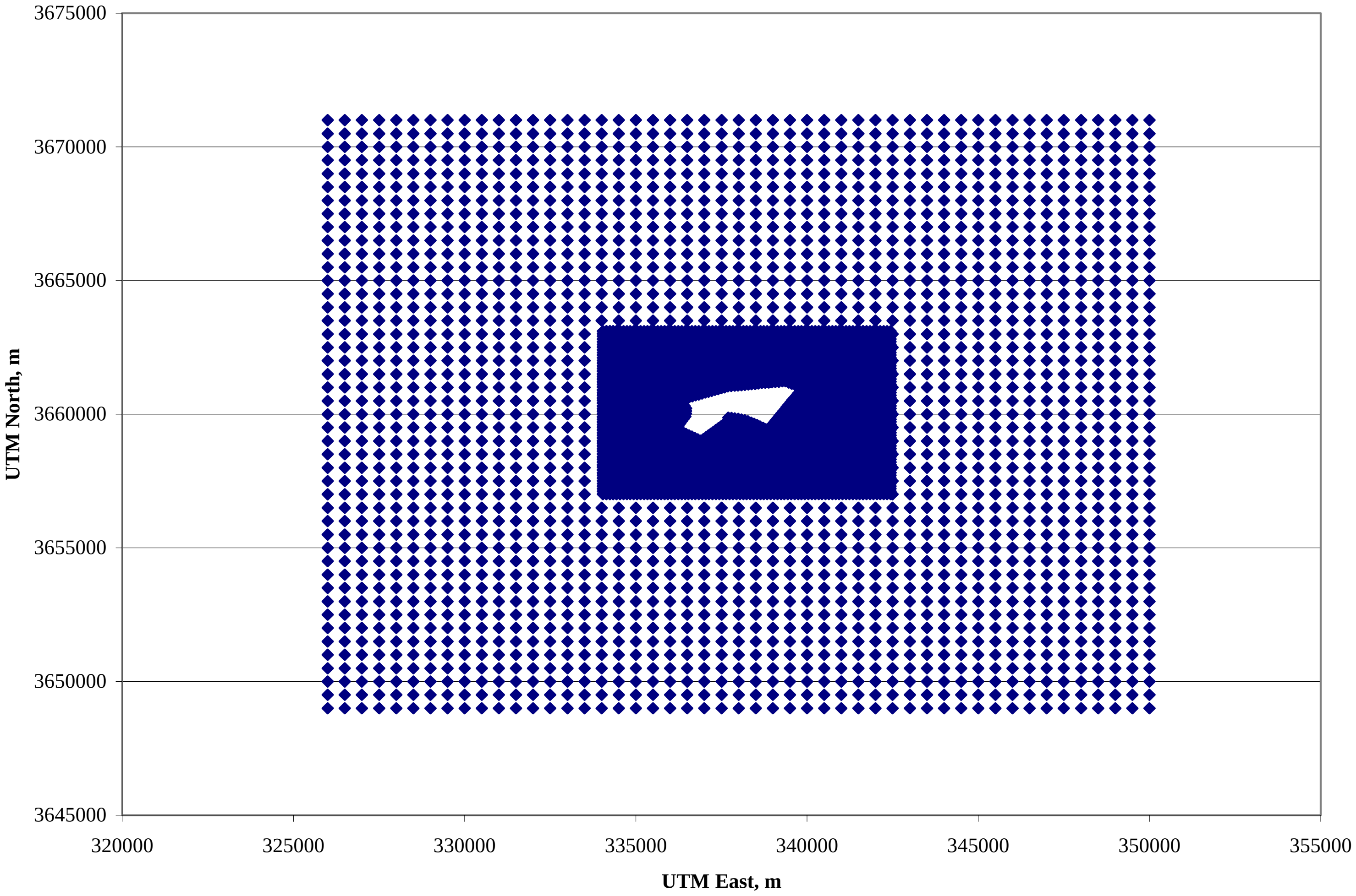


Image Source: USDA-FSA Aerial Photography Field Office, Salt Lake City, Utah 2007 (ortho_1-1_1n_s_ga303_2007_1.sid)

Prepared by: FC 1/17/08
Checked by: SAK 1/17/08

Figure 5-2 Entire Modeling Receptor Set



Prepared by: <u>LMG 1/17/08</u>
Checked by: <u>SAK 1/17/08</u>

Table 5-3 Screen Modeling Source Emissions

	UTM Coordinates		**$PM_{2.5}$ 24 Hour**	**$PM_{2.5}$ Annual**	**PM_{10} 24 Hour**	**PM_{10} Annual**	**SO_2 3 and 24 Hour**	**SO_2 Annual**	**NO_x**	**CO 1-Hour**	**CO 8-Hour**	**Pb**	**HF**	**H_2SO_4**	**Temperature**	**Height**	**Diameter**	**Velocity**	**Temperature**
	East (m)	**North (m)**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	°F	m	m	m/s	K
Coal-fired Boiler	337088.13	3659815.90	10.75	10.75	18.82	18.82	125.50	94.12	52.29	313.74	156.87	1.77E-02	0.31	5.23	140	137.16	9.14	18.55	333
Auxiliary Boiler	337338.40	3659776.00	7.26E-02	7.26E-02	0.60	0.60	1.51	1.51	3.02	2.54E-01	2.54E-01	2.72E-04	2.82E-04	1.81E-03	275	27.43	1.52	19.81	408
Cooling Tower No. 1	337021.84	3659703.97	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 2	337033.91	3659716.04	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 3	337033.91	3659691.90	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 4	337045.97	3659703.97	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 5	337045.97	3659679.83	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 6	337058.04	3659691.90	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 7	337058.04	3659667.76	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 8	337070.11	3659679.83	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 9	337070.11	3659655.69	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 10	337082.18	3659667.76	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 11	337082.18	3659643.62	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 12	337094.25	3659655.69	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 13	337094.25	3659631.55	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 14	337106.32	3659643.62	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 15	337106.32	3659619.48	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 16	337118.39	3659631.55	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 17	337118.39	3659607.41	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 18	337130.46	3659619.48	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 19	337130.46	3659595.34	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 20	337142.53	3659607.41	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 21	337142.53	3659583.27	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 22	337154.60	3659595.34	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 23	337154.60	3659571.20	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 24	337166.67	3659583.27	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 25	337166.67	3659559.13	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 26	337178.74	3659571.20	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 27	337178.74	3659547.06	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 28	337190.81	3659559.13	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 29	337190.81	3659534.99	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 30	337202.88	3659547.06	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 31	337202.88	3659522.92	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 32	337214.95	3659534.99	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 33	337214.95	3659510.86	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Cooling Tower No. 34	337227.02	3659522.92	2.78E-05	2.78E-05	6.35E-03	6.35E-03	-	-	-	-	-	-	-	-	68.00	15.24	12.19	6.07	293
Crusher House Dust Collector	337335.40	3660114.80	2.07E-02	2.07E-02	0.130	0.130	-	-	-	-	-	-	-	-	68.00	30.48	0.91	17.25	293
Tripper Decker	337350.40	3659853.00	1.56E-02	1.56E-02	9.72E-02	9.72E-02	-	-	-	-	-	-	-	-	68.00	59.13	0.79	17.45	293
Limestone Preparation Building	337101.10	3659891.40	7.29E-03	7.29E-03	2.70E-02	2.70E-02	-	-	-	-	-	-	-	-	-	18.29	54.81	0.001	293
Fly Ash Mechanical Exhausters (2)	337222.30	3659877.30	7.42E-03	7.42E-03	1.30E-02	1.30E-02	-	-	-	-	-	-	-	-	258	47.24	53.78	0.001	399
Fly Ash Silo	337222.30	3659890.40	4.63E-03	4.63E-03	8.10E-03	8.10E-03	-	-	-	-	-	-	-	-	177	47.24	54.81	0.001	354
Mercury Storage and Handling	337237.60	3659870.40	2.03E-03	2.03E-03	2.03E-03	2.03E-03	-	-	-	-	-	-	-	-	-	22.86	24.51	0.001	293
SO_3 Storage and Handling	337228.50	3659870.40	2.03E-03	2.03E-03	2.03E-03	2.03E-03	-	-	-	-	-	-	-	-	-	22.86	24.51	0.001	293
Soda Ash Storage and Handling	337293.70	3659690.70	1.01E-03	1.01E-03	1.01E-03	1.01E-03	-	-	-	-	-	-	-	-	-	22.86	24.51	0.001	293
Hydrated Lime Storage and Handling	337293.70	3659684.60	2.73E-04	2.73E-04	1.01E-03	1.01E-03	-	-	-	-	-	-	-	-	-	22.86	24.51	0.001	293
PRB Stackout	337317.75	3660421.69	1.30E-03	1.30E-03	8.10E-03	8.10E-03	-	-	-	-	-	-	-	-	68	33.53	30.02	0.001	293
Illinois No. 6 Stackout	337313.30	3660516.57	1.30E-03	1.30E-03	8.10E-03	8.10E-03	-	-	-	-	-	-	-	-	68	27.43	30.02	0.001	293
Limestone Stackout	337169.45	3660003.07	2.19E-03	2.19E-03	8.10E-03	8.10E-03	-	-	-	-	-	-	-	-	68	21.34	30.02	0.001	293

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Table 5-3 Screen Modeling Source Emissions (Continued)

							Area Source				**Volume Source**		
	UTM Coordinates		**PM$_{2.5}$ 24 Hour**	**PM$_{2.5}$ Annual**	**PM$_{10}$ 24 Hour**	**PM$_{10}$ Annual**	**PM$_{10}$ Emission Rate per Unit Area**	**PM$_{2.5}$ Emission Rate per Unit Area**	**Release Height**	**Vertices**	**Release Height**	**Initial Lateral Dimension**	**Initial Vertical Dimension**
	East (m)	**North (m)**	**g/s**	**g/s**	**g/s**	**g/s**	g/m^2-s	g/m^2-s	m	-	m	m	m
Bottom Ash Storage and Handling System	337315.58	3659846.66	1.15E-04	1.15E-04	7.57E-04	7.57E-04	2.95E-06	4.46E-07	3.05	4	-	-	-
Solid Material Handling-Ash	337801.37	3660642.88	5.21E-03	5.21E-03	9.48E-03	9.48E-03	1.99E-08	1.09E-08	6.86	8	-	-	-
Solid Material Handling-Gypsum	338256.02	3659829.94	5.21E-03	5.21E-03	9.48E-03	9.48E-03	8.78E-09	4.82E-09	6.86	16			
Limestone Rail Unloading	337262.54	3660047.50	9.05E-06	9.05E-06	5.98E-05	5.98E-05	3.55E-07	5.38E-08	4.57	4	-	-	-
Coal Rail Unloading	337509.97	3660430.83	5.60E-05	5.60E-05	3.70E-04	3.70E-04	2.21E-06	3.35E-07	4.57	4	-	-	-
Limestone Storage and Handling	337169.45	3660003.07	2.24E-03	8.46E-05	1.58E-02	5.64E-04	-	-	-	-	2.90	26.79	1.35
Inactive PRB Coal Pile Storage and Handling	337143.92	3660318.92	5.20E-03	5.20E-03	5.89E-02	5.89E-02	-	-	-	-	15.28	63.80	7.11
Inactive Illinois No. 6 Coal Pile Storage and Handling	337143.92	3660554.71	5.20E-03	5.20E-03	5.89E-02	5.89E-02	-	-	-	-	11.70	53.16	5.44
Active PRB Coal Pile	337317.75	3660421.69	4.44E-03	2.63E-04	2.96E-02	1.74E-03	-	-	-	-	15.21	10.14	7.08
Active Illinois No. 6 Coal Pile	337313.30	3660516.57	4.44E-03	2.63E-04	2.96E-02	1.74E-03	-	-	-	-	15.21	10.14	7.08
Solid Material Handling Haul Road Node 1	337237.54	3659890.21	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 2	337266.14	3659897.90	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 3	337294.15	3659907.74	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 4	337324.63	3659907.74	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 5	337355.11	3659907.74	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 6	337385.59	3659907.74	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 7	337416.07	3659907.74	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 8	337446.45	3659908.93	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 9	337467.28	3659930.67	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 10	337486.88	3659954.02	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 11	337507.83	3659976.08	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 12	337533.39	3659992.54	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 13	337562.23	3660002.17	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 14	337592.55	3660004.53	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 15	337623.03	3660004.53	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 16	337653.51	3660004.53	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 17	337683.99	3660004.53	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 18	337714.47	3660004.53	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 19	337744.95	3660004.53	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 20	337775.43	3660004.53	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 21	337805.82	3660006.54	1.12E-04	1.12E-04	7.48E-04	7.48E-04	-	-	-	-	2.44	4.48	1.7

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

5.2 FUGITIVE PARTICULATE MODELING

The modeling of fugitive PM_{10} and $PM_{2.5}$ emissions from the paved SMHF haul road followed the procedures outlined in the Georgia EPD "Guideline for assuring acceptable ambient concentration of PM_{10} in areas impacted by quarry operation producing crushed stones – October 15, 2004". Emissions from the paved SMHF haul road were estimated using the AP-42 equations outlined in the quarry modeling guidance. For emission estimation purposes the SMHF haul road was divided into segments and the amount of traffic through the Washington county power plant was estimated based on the amount of ash and gypsum generated from coal combustion. The AP-42 calculations utilize average truck weights, number of wheels on the trucks, silt content, and silt moisture content to calculate the lbs of PM_{10}/ $PM_{2.5}$ emissions per vehicle mile traveled. Estimates for the number of trucks trips and the length of the SMHF haul road were then used to calculate the total traveled distance. The total travel distance and PM emission factors were used to calculate emissions for each road segment. Sample calculations are included in Exhibit A of the permit application.

Once each road segment's PM_{10}/$PM_{2.5}$ emissions were calculated, each segment was divided into the appropriate volume sources as outlined in the quarry modeling guidance. The Site layout found in Exhibit B provides a map of the site, which locates all road segments included in the modeling analysis. The SMHF haul road was modeled as 10 foot x 40 foot volume sources. The effective height for all road dust volume sources were estimated at 8 feet in accordance with modeling guidance.

Emissions from the SMHF and the PRB and Illinois No. 6 Inactive Coal Piles were calculated based on emission factor equations obtained from AP-42 Table 11.9-1. The emission factor equations utilize silt and moisture contents to calculate PM_{10}/$PM_{2.5}$ emission rates, which were obtained from AP-42 Table 11.9-3. Once emissions were calculated, each source was modeled as an area poly source as outlined in Section 3.3.2.3 of the AERMOD User Guide (September 2004).

Drop point emissions from Coal Rail Unloading, Limestone Rail Unloading, and Bottom Ash Transfer were calculated using the drop point emission factor equation found in AP-42 Section 13.2.4.3. The equation utilizes the mean wind speed and moisture content of the material being handled to calculate an emission per unit ton of material handled factor. After computing emission rates, each drop point was modeled as an area poly source according to Section 3.3.2.3 of the AERMOD User Guide (September 2004).

Emissions from the Powder River Basin and Illinois No. 6 Active Piles were calculated using the Industrial Wind Erosion equations found in AP-42 (Section 13.2.5).

5.3 METEOROLOGICAL DATA

The Georgia EPD provided MACTEC with AERMET (version 06341) pre-processed meteorological data files based on surface data for the Macon Airport meteorological station and upper air data from the Centreville meteorological station for the 1987-1991 five year period. The development of the AERMET data set requires the assessment of surface characteristics of the surface meteorological station. These characteristics include albedo, bowen ratio, and surface roughness. Albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption, bowen ratio is an indicator of surface moisture, and surface roughness length is related to the height of obstacles in relation to wind flow. The AERMET data was processed using the surface characteristics assessed by Georgia EPD. A comparative analysis of surface characteristics surrounding the Plant Washington in Sandersville, Georgia and the surface meteorological station was conducted, according to the AERMOD Interim Guidance document.

The surface characteristics surrounding Plant Washington were compared to surface characteristics surrounding the surface meteorological station at the Macon Airport. Figure 5-3 is an aerial photo centered on the Macon airport surface meteorological data station and Figure 5-4 is an aerial photo of the Plant Washington. Each aerial photo was divided into the four sections: Section 1 from 350° to 80°, Section 2 from 80° to 140°, Section 3 from 140° to 220°, and Section 4 from 220° to 350°. These segments corresponded to the segments that were used in the AERMET processing. Table 5-4 shows a qualitative comparison between the surface characteristics at the proposed coal-fired power plant and the Macon Airport. Based on this comparative analysis, the Macon Airport justifiably represents the meteorological conditions at the proposed site.

Figure 5-3 Aerial View of Macon Surface Meteorological Station in Macon, Georgia

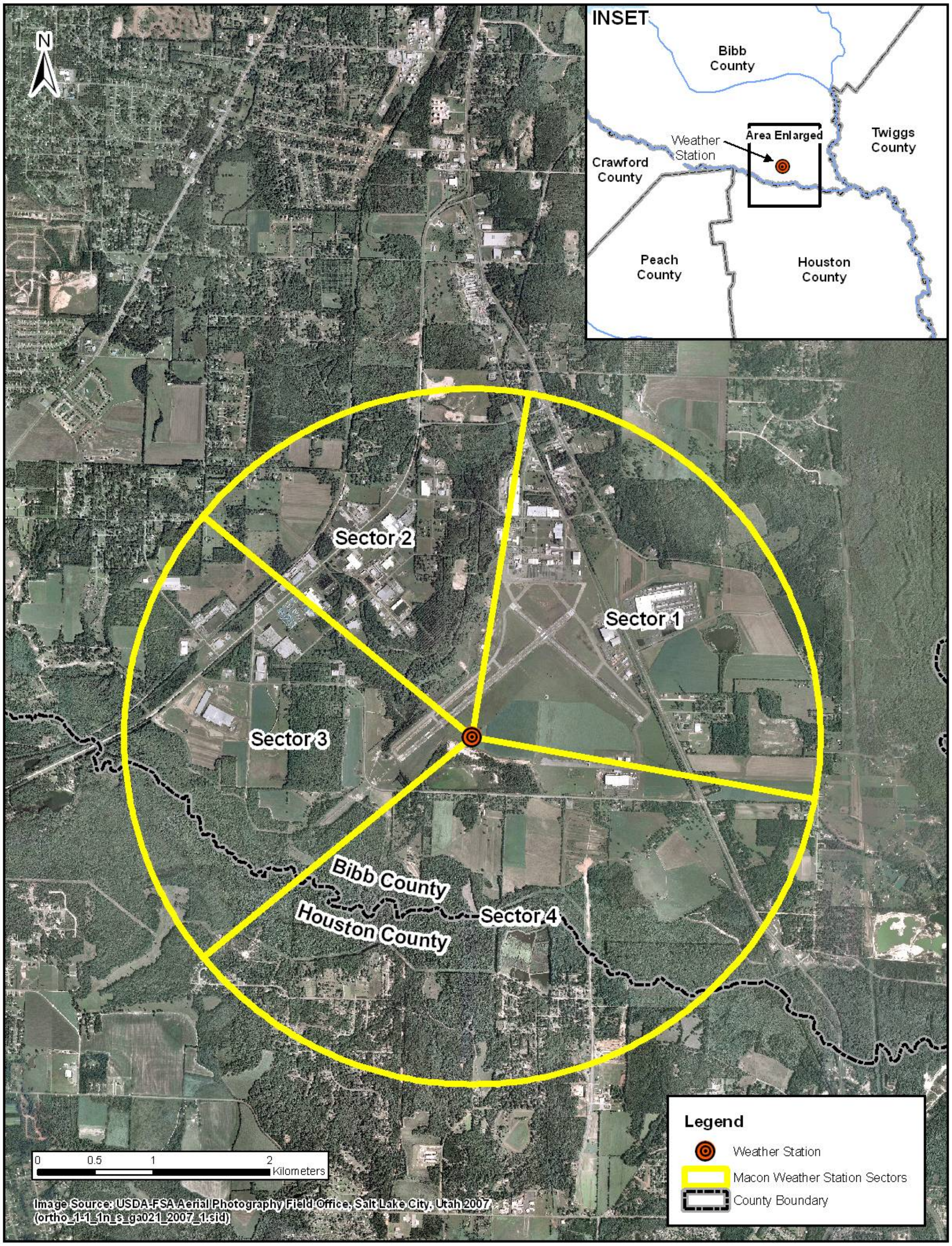


Image Source: USDA-FSA Aerial Photography Field Office, Salt Lake City, Utah 2007 (ortho_1-1_1n_s_ga021_2007_1.sid)

Prepared by: FC 1/17/08
Checked by: SAK 1/17/08

Figure 5-4 Aerial View of Plant Washington in Sandersville, Georgia

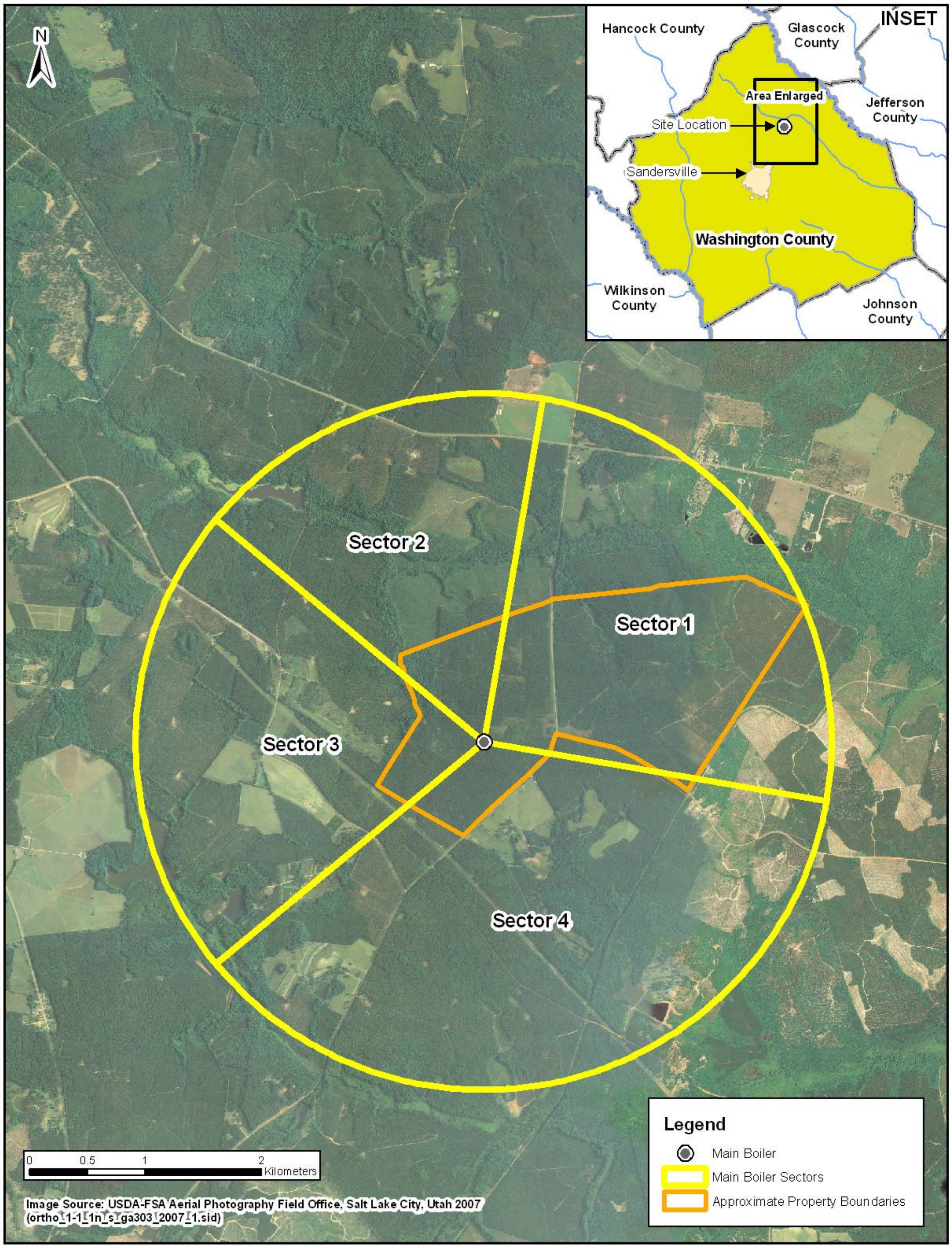


Image Source: USDA-FSA Aerial Photography Field Office, Salt Lake City, Utah 2007
(ortho_1-1_1n_s_ga303_2007_1.sid)

Prepared by: FC 1/17/08
Checked by: SAK 1/17/08

Table 5-4 Qualitative Comparisons between the Surface Characteristics at Plant Washigton and the Macon Airport

Surface Characteristic	Macon Airport	Plant Washington
Albedo – Total incident radiation reflected back into space. 0.1 – Deciduous Forest 0.9 – White Snow	Green area except for a few buildings and roads 0.1 – 0.2	Green area except for a few buildings and roads 0.1 – 0.2
Bowen Ratio – Indication of surface moisture. 0.10 – Over water 10 – Over Desert	For Sectors 1 and 3 – Elevated surface with excellent surface run-off with little standing water ~2 For Sector 2 – Poor surface run-off due to depression and poor soil permeability due to red clay. < 1 For Sector 4 – Primarily vegetation with good surface run-off ~1	For Sectors 1 and 3 Excellent surface run-off with little standing water ~2 For Sector 2 – Poor infiltration due to concrete surface; therefore, a lot of standing water < 1 For Sector 4- Primarily vegetation with good surface run-off ~1
Surface Roughness Length – Height of obstacles in principal where horizontal wind velocity is zero. 0.001 m – Water >1 m - for Forest or Urban	For Sectors 1 and 4 trees and buildings are at an average height of 30 ft except for airport runway ~1 For Sectors 2 and 3 – areas are predominantly green fields <1	For Sectors 1 and 4 trees, are at an average height of 30 ft except for cultivated areas ~1 For Sectors 2 and 3 – areas are predominantly green fields and cultivated areas <1

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

5.4 PSD SCREEN MODELING RESULTS

The screen modeling for PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, VOC, Pb, and Fluorides (as HF) were used to determine whether the emission increases resulted in concentrations that exceed the SILs or the significant monitoring levels. Refined modeling is required and preconstruction monitoring must be evaluated if these significant levels are exceeded. Tables 5-5 through 5-8 show the results of the screen modeling for each pollutant, which are discussed in more detail below.

5.4.1 $PM_{2.5}$ Screen Model Results

The screen modeling results for $PM_{2.5}$, as presented in Table 5-5, do not exceed the lowest recently proposed SILs for the 24-hour and annual averaging periods (option 3 under the USEPA proposal). This modeling evaluation is not a regulatory requirement under the current air quality rules; however, the results are included to demonstrate that the project will not have a significant impact on $PM_{2.5}$ concentrations in the area around the proposed plant. The lowest of the proposed preconstruction monitoring level was also not exceeded.

Table 5-5 $PM_{2.5}$ Screening Results

24-hour Averaging Period			
Year of Model Run	**Maximum Concentration (µg/m^3)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	1.00	338337	3658911
1988	1.01	338037	3659711
1989	1.10	338037	3659711
1990	0.97	337937	3659411
1991	0.97	338537	3659411
Significant Monitoring Level: 2.3 µg/m^3			
Significant Impact Level: 1.2 µg/m^3			
Annual Averaging Period			
Year of Model Run	**Maximum Concentration (µg/m^3)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	0.15	337701.50	3659868.00
1988	0.16	337889.62	3659844.50
1989	0.19	338084.12	3659798.00
1990	0.15	338084.12	3659798.00
1991	0.15	337701.5	3659868.00
Significant Impact Level: 0.3 µg/m^3			

µg/m^3 = micrograms per cubic meter
km = Kilometer

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

5.4.2 PM_{10} Screen Model Results

The screen modeling results for PM_{10}, as presented in Table 5-6, do not exceed the SILs for the 24-hour and annual averaging periods; therefore, refined modeling is not required for the pollutant. The preconstruction monitoring level was also not exceeded.

Table 5-6 PM_{10} Screening Results

24-hour Averaging Period			
Year of Model Run	**Maximum Concentration (µg/m³)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	3.80	337214.66	3660874.25
1988	4.20	336838.34	3660738.75
1989	4.49	337214.66	3660874.25
1990	4.06	337026.09	3660807.50
1991	4.22	336931.34	3360774.00
Significant Impact Level: 5 µg/m			
Significant Monitoring Concentration: 10 µg/m³			

Annual Averaging Period			
Year of Model Run	**Maximum Concentration (µg/m³)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	0.60	337026.09	3660807.50
1988	0.67	336931.94	3660774.00
1989	0.73	336931.94	3660774.00
1990	0.67	337026.09	3660807.50
1991	0.55	337026.09	3660807.50
Significant Impact Level: 1 µg/m³			

µg/m³ = Micrograms per cubic meter
km = Kilometer

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

5.4.3 NO$_x$ Screen Model Results

The NO$_x$ screen model results, as presented in Table 5-7 do not exceed the NO$_x$ SIL on an annual averaging period basis; therefore a refined modeling evaluation is not required. The modeled results also did not exceed the significant monitoring concentration.

Table 5-7 NOx Screening Results

NO$_x$ Annual Screen Results			
Year	**Maximum Concentration**	**UTM Coordinate (m)**	
-	**μg/m^3**	**East**	**North**
1987	0.59	338137	3659011
1988	0.57	338137	3659211
1989	0.65	338237	3659611
1990	0.57	338137	3659111
1991	0.56	338137	3659111
PSD Significance Level: 1 μg/m^3			

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

5.4.4 CO Screen Model Results

As shown in Table 5-8, the modeled emissions do not exceed the CO SILs on a 1-hour or 8-hour averaging period. This result indicates that no further modeling is required. The significant monitoring concentration was also not exceeded; therefore, preconstruction monitoring is not required for CO.

Table 5-8 CO Screening Results

CO 1-Hour Screen Results			
	Maximum Concentration	**UTM Coordinate (m)**	
Year	**μg/m^3**	**East**	**North**
1987	124.2	337937	3661211
1988	127.2	335337	3662311
1989	113.3	338037	3662011
1990	105.1	337437	3662711
1991	97.1	337037	3662211
PSD Significance Level: 2,000 μg/m^3			
CO 8-Hour Screen Results			
	Maximum Concentration	**UTM Coordinate (m)**	
Year	**μg/m^3**	**East**	**North**
1987	27.6	336137	3659011
1988	32.2	338037	3659611
1989	35.5	338037	3659711
1990	32.5	337937	3659411
1991	30.1	337437	3658911
PSD Significance Level: 500 μg/m^3			

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

5.4.5 SO_2 Screen Model Results

The SO_2 screen model results, as presented in Table 5-9, exceed the SO_2 SILs for all averaging periods; therefore, a refined modeling analysis is required. The modeled results do not exceed the significant monitoring concentration.

Table 5-9 SO_2 Screening Results

3-hour Averaging Period				
Year of Model Run	**Maximum Concentration (μg/m^3)**	**Location of Receptors (UTM)**		**Area of Impact Radius (km)**
		X	**Y**	
1987	31.17	337737	3659111	1.85
1988	28.44	338037	3659711	1.33
1989	32.53	338037	3659711	1.47
1990	31.35	337837	3659311	1.47
1991	30.41	336537	3658911	1.45
Significant Impact Level: 25 μg/m^3				Max.: 1.85

24-hour Averaging Period				
Year of Model Run	**Maximum Concentration (μg/m^3)**	**Location of Receptors (UTM)**		**Area of Impact Radius (km)**
		X	**Y**	
1987	11.23	338337	3658911	5.38
1988	10.66	338137	3659611	4.01
1989	11.08	338037	3659611	4.98
1990	10.63	337937	3659411	4.89
1991	10.88	338637	3659411	4.96
Significant Impact Level: 5 μg/m^3				Max: 5.38
Significant Monitoring Concentration: 13 μg/m^3				

Annual Averaging Period				
Year of Model Run	**Maximum Concentration (μg/m^3)**	**Location of Receptors (UTM)**		**Area of Impact Radius (km)**
		X	**Y**	
1987	1.06	338137	3659011	1.60
1988	1.03	338137	3659211	1.39
1989	1.17	338237	3659611	1.65
1990	1.02	338137	3659111	1.35
1991	1.01	338137	3659111	1.35
Significant Impact Level: 1 μg/m^3				Max.: 1.65

km = Kilometer

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

5.4.6 Hydrogen Fluoride Screen Model Results

The HF screen model results, as presented in Table 5-10, did not exceed the HF significant monitoring concentration on a 24-hour averaging period basis.

Table 5-10 HF Screening Results

24-Hour Averaging Period			
Year of Model Run	**Maximum Concentration (µg/m^3)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	0.02775	338337	3658911
1988	0.02633	338137	3659611
1989	0.02737	338037	3659611
1990	0.02625	337937	3659411
1991	0.02688	338637	3659411
Significant Monitoring Concentration: 0.25 µg/m^3			

Completed by: <u>LMG 1/17/08</u>
Checked by: <u>SAK 1/17/08</u>

5.4.7 Lead Screen Model Results

The Pb screen model results, as presented in Table 5-11, did not exceed the Pb significant monitoring concentration on a quarterly averaging period basis.

Table 5-11 Pb Screening Results

Calendar Quarter Averaging Period[1]			
Year of Model Run	**Maximum Concentration (µg/m^3)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	0.00189	337937	3661211
1988	0.00194	335337	3662311
1989	0.00173	338037	3662011
1990	0.00160	337437	3662711
1991	0.00148	337037	3662211
Significant Monitoring Concentration: 0.10 µg/m^3			
1. Multiplied the 1-hr average result by 0.27 to convert to Calendar Quarter Average per USEPA "A Screening Procedure for the impacts of Air Pollution Sources on Plants, Soils, and Animals" (EPA/2-81-078 December 1980)			

Completed by: <u>LMG 1/17/08</u>
Checked by: <u>SAK 1/17/08</u>

5.4.8 Alternative Modeling Evaluations

The primary goal of the above modeling evaluation was to demonstrate that the proposed plant will achieve compliance with all air quality standards during worst case operational conditions, which will occur during the majority of the time. Two additional operational modes (reduced load operation and startup operation) were evaluated for their potential impacts on air quality. The results from these evaluations are discussed in detail below.

5.4.8.1 Reduced Load Operational Evaluation

The proposed plant will at times operate at reduced loads (estimated at 40% production capacity) during the shoulder months (typically during spring and fall when power demands are below peak levels). The screen models were therefore rerun at this reduced operational load to evaluate the impact on air quality. The process (boiler/turbine) is less efficient at this reduced power production load. To produce 40% power the boiler will have to operate at approximately 50% fuel firing rate. This means that emissions and air flow rate from the main boiler stack will be at 50% of the previously modeled levels. The plant will continue to meet all its emission limits on a lb/MMBtu basis during this reduced loading period. Table 5-12 below summarizes the results of this modeling analysis. The results from this analysis found that the maximum impacts for all pollutants are below the significant impact levels, except for SO_2, for which a refined modeling analysis was completed.

Table 5-12 40% Load and Startup Model Modeling Results

Pollutant	**Avg. Period**	**Significant Impact Level (µg/m^3)**	**40% Operational Load Mode (µg/m^3)**	**Startup Mode (µg/m^3)**
$PM_{2.5}$	24-hr	1.20	0.91	1.18
$PM_{2.5}$	Annual	0.30	0.19	0.195
PM_{10}	24-hr	5	4.46	4.53
PM_{10}	Annual	1	0.72	0.73
SO_2	3-hr	25	25.68	32.98
SO_2	24-hr	5	8.76	12.79
SO_2	Annual	1	1.30	1.54
CO	8-hr	500	53.82	81.09
CO	1-hr	2,000	80.15	369.55
NOx	Annual	1	0.54	0.78

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

5.4.8.2 Startup Modeling Results

In addition to the 40% load conditions a modeling evaluation was also completed for the startup/shutdown conditions. All pollution control equipment will be operated during the startup of the boiler except for the SCR system. The SCR is ineffective below a certain temperature (approx. 450 degrees F) and therefore would not reduce NO_x if operated. The injection of ammonia into the flue gas during cold conditions can result in the corrosion of the downstream pollution control equipment. For this reason, the SCR will not be operating at maximum capacity until the startup process is complete. The NO_x 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. CO emissions from the boiler will also be greater than their maximum 100 percent capacity levels for brief periods during the startup period as the unit achieves stable combustion.

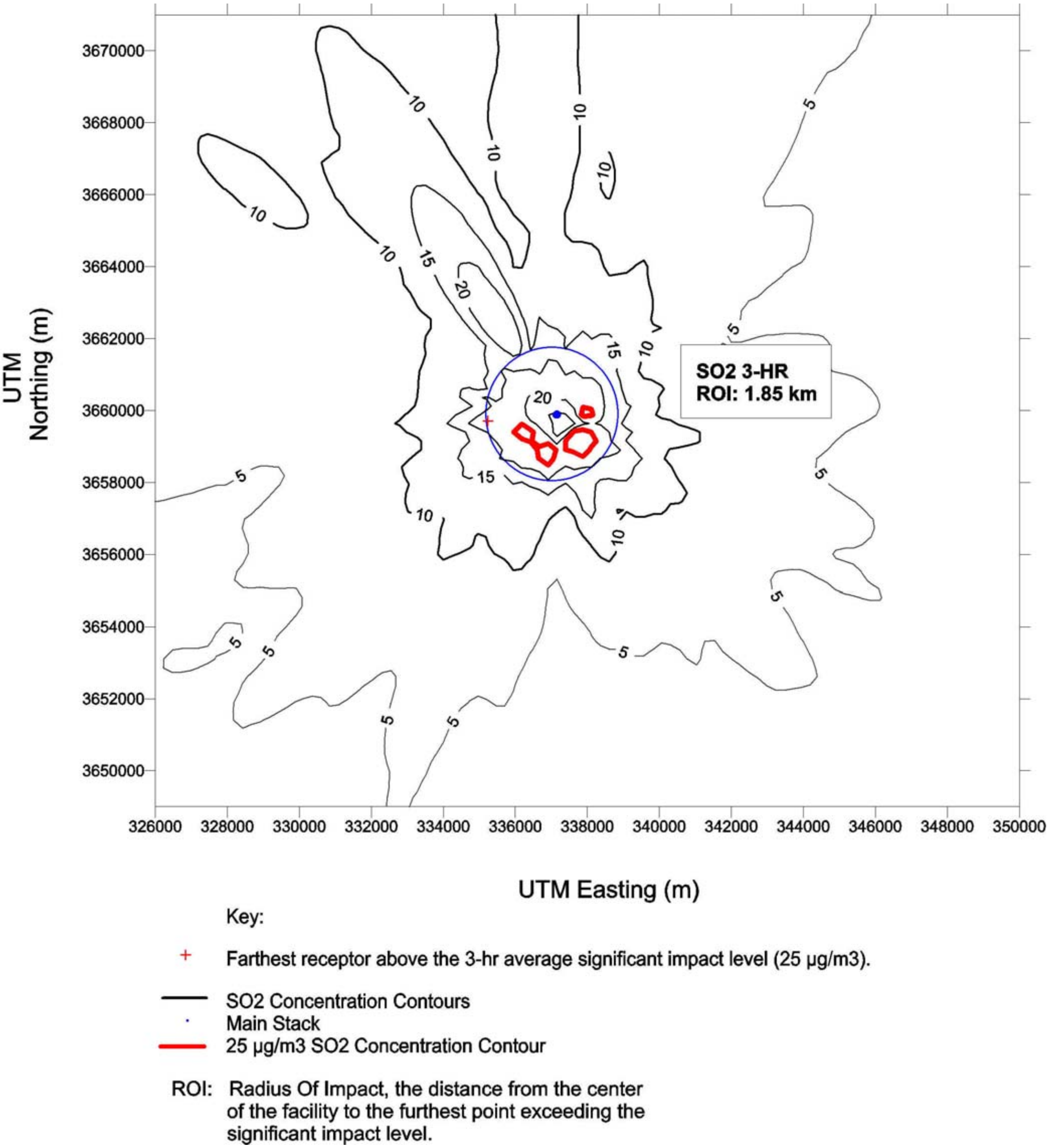
In addition the auxiliary boiler will be operated during both startup and shutdown of the main boiler. The primary purpose of the auxiliary boiler operation is to provide steam to the turbine during the startup and shutdown periods so as to prevent damage to the unit, which could be caused by large swings in steam loading to the turbine. The startup mode modeling included the operation of the auxiliary boiler at maximum firing rate 876 hr/yr (the maximum expected hours of operation) and includes 10 cold startups of the main boiler per year (an expected typical value for the boiler). The AERMOD model allows for the input of variable hourly emission rates for a given pollutant. A variable emission rate file was developed for all modeled pollutants from the main and auxiliary boilers with the above identified operational conditions.

5.5 SIGNIFICANT IMPACT AREA DETERMINATION AND DETERMINATION OF OFF-SITE EMISSIONS DATA FOR REFINED SO2 MODELING

The Area of Impact (AOI) was determined to be a circular area with the radius extending from the center of Plant Washington to the farthest point that exceeds the applicable SIL as predicted by the screen model. Refined modeling is required for all receptors within the AOI. Five years of meteorological data were used to determine the worst-case AOI for SO_2 and each averaging period. Figures 5-5 through 5-7 show the analysis output for each pollutant's averaging period for the corresponding worst-case years (largest AOI).

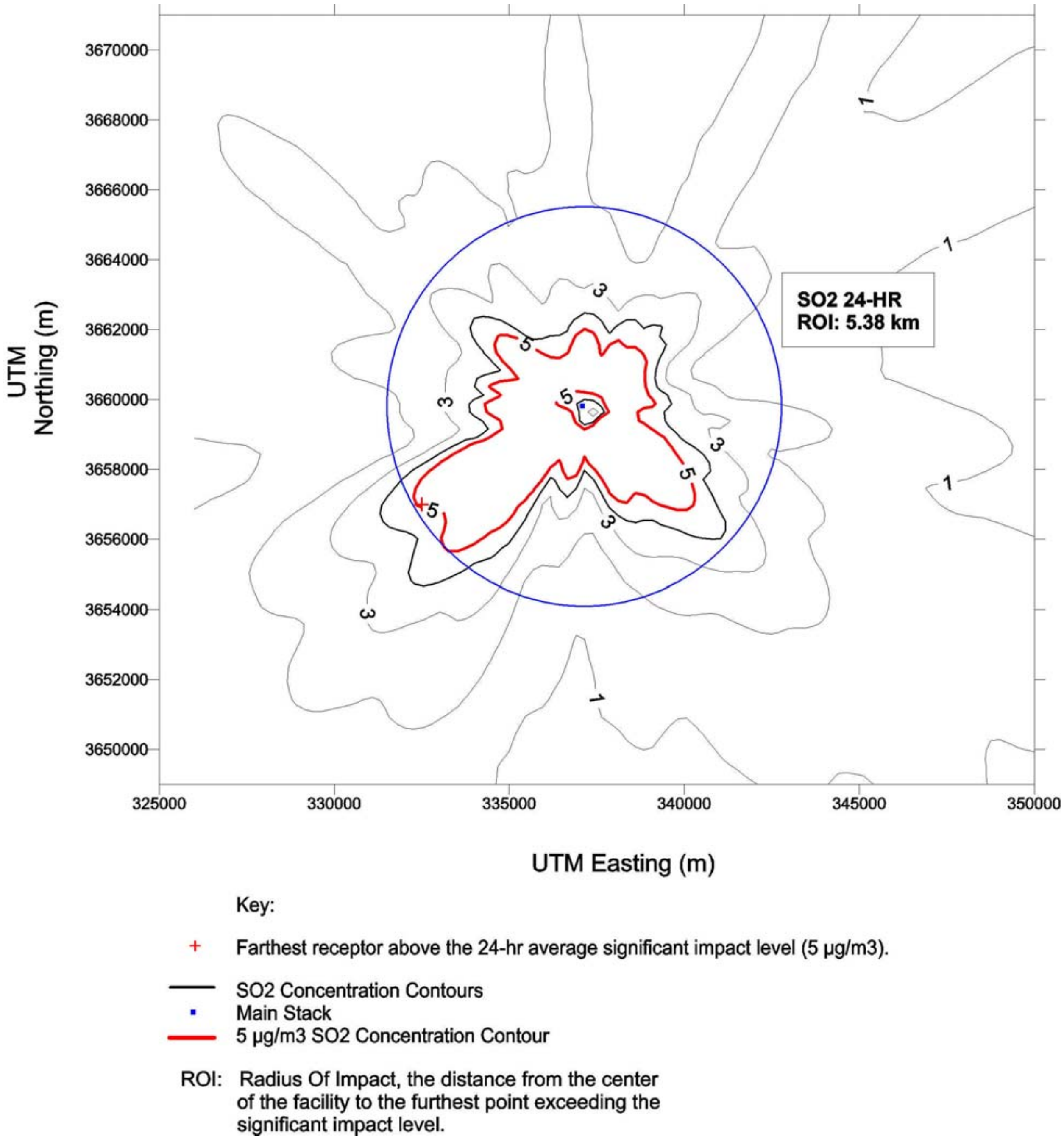
USEPA guidance states that 50 kilometers must be added to the impact radius to complete the off-site emission source retrieval. A list of sources emitting SO_2 within 56 kilometers of the proposed site was requested from GA EPD to determine the off-site sources that would required to be included in the modeling. GA EPD provided spreadsheets that identified all sources within the SIA, along with their corresponding emission rates and stack parameters. These spreadsheets also identified the sources' status as "PSD increment consuming," or "PSD increment expander" for increment-modeling purposes. The PSD-increment-consuming sources were modeled as positive emission rates and the PSD-expanding sources were modeled as negative emission rates for the PSD increment models. For the purposes of completing the NAAQS modeling, the Georgia EPD provided the 2005 emission inventory database. All sources of SO_2 emissions in the database that are within 56 km of the proposed site were included in the modeling evaluation. The stack parameters from the database were used in the modeling analysis. The emission rates were, however, based on a review of each plant's Title V permit applications and Title V permits. This data review was completed to determine the allowable SO_2 emissions rate for each source being modeled. All NAAQS models included the increment consumers. Exhibit C provides the modeled data for all off site sources included in the refined SO_2 modeling.

Figure 5-5 Significant Impact Area: 1987 SO_2 Screening Results, 3-hour



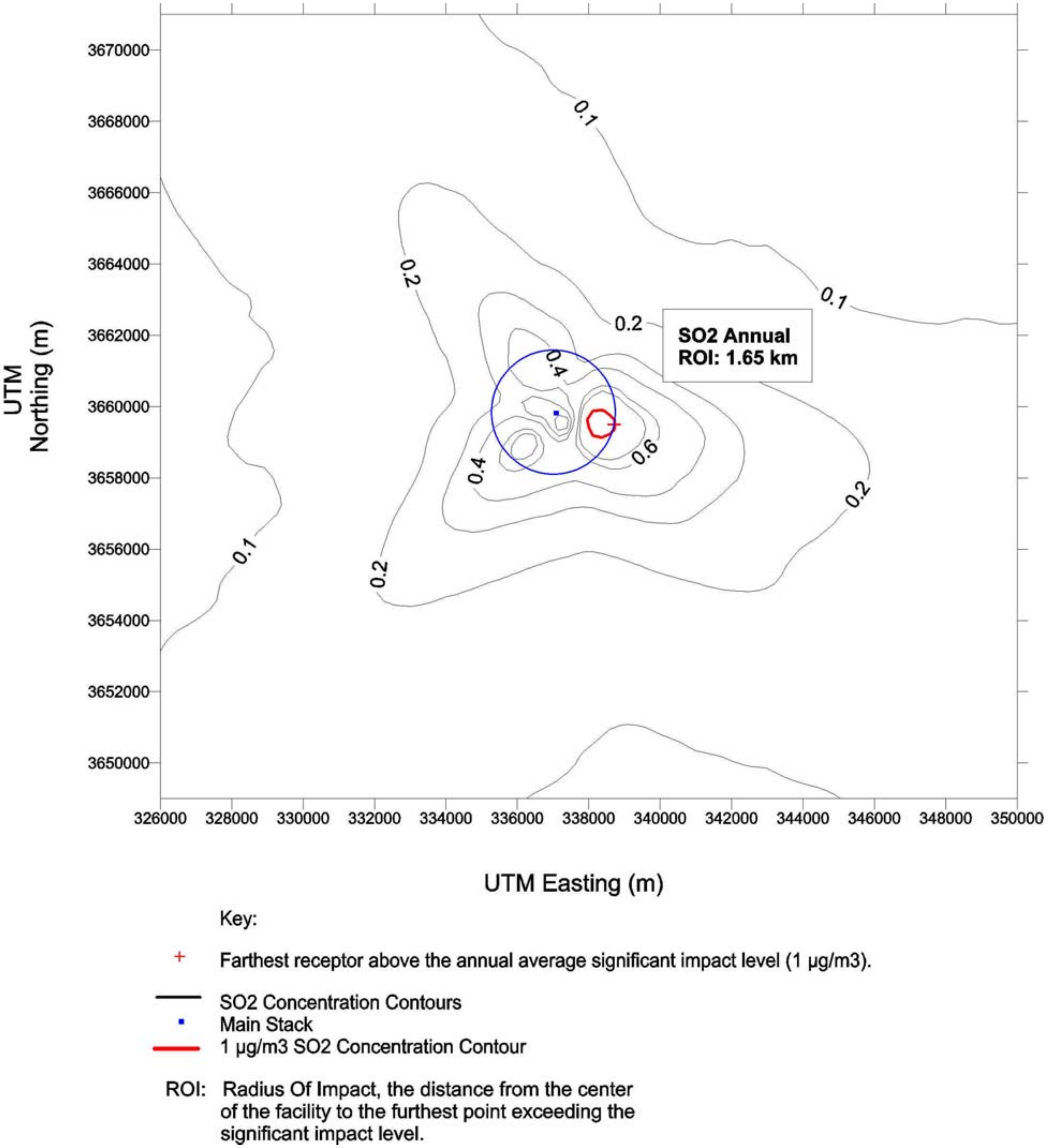
Completed by: <u>LMG 1/17/08</u>
Checked by: <u>SAK 1/17/08</u>

Figure 5-6 Significant Impact Analysis: 1987 SO_2 Screening Results, 24-hour



Completed by: <u>LMG 1/17/08</u>
Checked by: <u>SAK 1/17/08</u>

Figure 5-7 Significant Impact Area: 1989 SO_2 Screening Results, Annual



Completed by: <u>LMG 1/17/08</u>
Checked by: <u>SAK 1/17/08</u>

5.6 REFINED MODELING ANALYSIS

Refined modeling was required for SO_2 based on the screen model results; therefore, modeling was performed to demonstrate compliance with the PSD increment and NAAQS standards, which are listed in Table 5-13. A background ambient concentration was obtained to determine compliance with the NAAQS standards for SO_2. This background concentration must be added to the NAAQS modeling results before a comparison to the standards can be made. The same meteorological data and receptor data used for the screen modeling was used for the refined modeling.

Table 5-13 Background, MAAQS, and PSD Increment Standards

Pollutant	Averaging Period	Background Concentration (μg/m^3)[1]	NAAQS (μg/m^3)	PSD Increment Standard (μg/m^3)
SO_2	3-hour	187	1,300	512
	24-hour	41	365	91
	Annual	8	80	20

μg/m^{3} = micrograms per cubic meter

1. As provided by Georgia EPD

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

5.7 NATIONAL AMBIENT AIR QUALITY STANDARD MODELING RESULTS

The high-second-high NAAQS concentration was used for the SO_2 24-hour and 3-hour averaging periods. The high-second-high concentration is the highest of the second high results from each of the five years of modeled meteorological data. The highest-second-high concentration will be the output for all receptors, and these data will be used for comparison to the standard. For the annual standards, each year of meteorological data was modeled and the highest value from all five models was compared to the annual standard. The NAAQS modeling included all proposed emission sources at their maximum hourly emission rates, as well as the off-site sources that are within the AOI. The refined SO_2 modeling (NAAQS and PSD Increment) included only those receptors that were within the largest calculated SIA for SO_2.

Table 5-14 presents the results for SO_2 and demonstrates compliance with the 3-hr, 24-hr, and annual standards. If the maximum result from all five years of models for each averaging period was located at a receptor which was not in the 100 meter spacing area, four additional receptors at 100 meter spacing were added around the maximum in order to ensure that the real maximum had been identified. The maximum result from all five of these receptors (the original plus the four additional receptors) is reported in the table.

Table 5-14 SO$_2$ NAAQS Modeling Summary

SO$_2$ 3-Hour Screen Results			
Year	**Maximum Concentration**	**UTM Coordinate (m)**	
-	**µg/m^3**	**East**	**North**
1987	71.0	333000	3663500
1988	88.3	334000	3655000
1989	93.6	334000	3655000
1990	73.1	338137	3659611
1991	74.4	332000	3662500
Maximum Concentration: 93.6 µg/m^3			
Background Concentration: 187 µg/m^3			
Combined Concentration: 280.6 µg/m^3			
NAAQS Level: 1,300 µg/m^3			
SO$_2$ 24-Hour Screen Results			
Year	**Maximum Concentration**	**UTM Coordinate (m)**	
-	**µg/m^3**	**East**	**North**
1987	22.6	337837	3659111
1988	26.4	334500	3664500
1989	24.4	338137	3659711
1990	25.9	338137	3659111
1991	22.8	338237	3659311
Maximum Concentration: 26.4 µg/m^3			
Background Concentration: 41 µg/m^3			
Combined Concentration: 67.4 µg/m^3			
NAAQS Level: 365 µg/m^3			
SO$_2$ Annual Screen Results			
Year	**Maximum Concentration**	**UTM Coordinate (m)**	
-	**µg/m^3**	**East**	**North**
1987	4.0	338037	3659011
1988	4.6	336037	3659111
1989	5.1	338137	3659611
1990	4.1	336137	3659111
1991	4.2	336137	365911
Maximum Concentration: 5.1 µg/m^3			
Background Concentration: 8 µg/m^3			
Combined Concentration: 13.1 µg/m^3			
NAAQS Level: 80 µg/m^3			

Completed by: JDC 1/17/08
Checked by: SAK 1/17/08

5.8 PSD INCREMENT MODELING RESULTS

PSD increment modeling was completed in addition to NAAQS modeling. One goal of the PSD increment modeling is to determine the increase in ground-level concentrations of SO_2 since its established baseline date (1975). Another goal is to determine whether the increases exceed the allowable PSD increments for the corresponding pollutants. The proposed power plant is a green-field facility; therefore, all emission sources are new and consume PSD increment.

The PSD increment model also includes off-site emission sources, which are increment consumers or expanders. As discussed previously, the Georgia sources were identified as consumers or expanders in the spreadsheets provided by GA EPD. The consumers were modeled as positive sources, while the expanders were modeled as negative sources. The receptor grid and meteorological data used for the NAAQS modeling were used for the PSD increment consumption modeling. The refined SO_2 modeling (NAAQS and PSD Increment) included only those receptors that were within the largest calculated SIA for SO_2.

Table 5-15 compares the highest modeling results for the annual averaging period and the highest second high for the 3-hour and 24-hour to the PSD SO_2 increment standards. Compliance with all standards is demonstrated.

Table 5-15 SO_2 PSD Increment Modeling Summary

PSD INCREMENT			
SO_2 3-Hour Screen Results			
County	**Maximum Concentration**	**UTM Coordinate (m)**	
-	**µg/m^3**	**East**	**North**
1987	27.88	336937	3658811
1988	28.26	338137	3659711
1989	32.51	337937	3659711
1990	30.26	338037	3659511
1991	28.64	337437	3658811
PSD Increment Level: 32.51 µg/m^3			
SO_2 3-hour PSD Increment Standard: 512 µg/m^3			
SO_2 24-Hour Screen Results			
Year	**Maximum Concentration**	**UTM Coordinate (m)**	
-	**µg/m^3**	**East**	**North**
1987	9.95	338337	3658811
1988	10.71	338237	3659611
1989	11.17	338137	3659611
1990	10.41	338137	3659411
1991	10.23	337837	3659111
PSD Increment Level: 11.17 µg/m^3			
SO_2 24-hour PSD Increment Standard: 91 µg/m^3			
SO_2 Annual Screen Results			
Year	**Maximum Concentration**	**UTM Coordinate (m)**	
-	**µg/m^3**	**East**	**North**
1987	1.34	338137	3659011
1988	1.27	338137	3659211
1989	1.41	338237	3659611
1990	1.25	338137	3659111
1991	1.25	338137	3659111
PSD Increment Level: 1.41 µg/m^3			
SO_2 Annual PSD Increment Standard: 20 µg/m^3			

Completed by: JDC 1/17/08
Checked by: SAK 1/17/08

6.0 AIR TOXICS MODELING

The proposed project was evaluated for compliance with the Georgia Air Toxics program using the "Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions" dated June 21, 1998. The first step was to calculate the potential emissions of all toxic pollutants from Plant Washington. The calculations are based on USEPA AP-42 emission factors for sub-bituminous coal, natural gas, and fuel oil (distillate) combustion. Exhibit C provides the toxic emission calculations and the development of the AACs for the project.

For each toxic pollutant identified, an allowable ambient concentration was developed by following the Georgia guidelines. The Georgia guidelines prioritize the available resources for toxicity data. First priority is given to inhalation reference concentrations (RfC) and Risk Based Air Concentrations (RBAC), which are identified in the USEPA's Integrated Risk Information System (IRIS) database, followed by OSHA PEL standards, ACGIH TLVs, NIOSH RELs, and LD50 toxicity data. AACs developed from worker exposure levels are based on 40 hours/week of exposure and must be adjusted to account for the potential exposure of the public (7 days/week, 24 hours/day). This correction along with the application of a safety factor of 300 for carcinogenic compounds and 100 for non-carcinogenic compounds is utilized in the development of AACs from worker exposure standards. The safety factor is applied to account for persons who may be sensitive to exposure to these pollutants. Toxicity data taken from the IRIS database does not require any adjustments because exposures to persons with respiratory maladies, young children, or the elderly were taken into account in the determination of these values. Short-term exposures are addressed using OSHA, NIOSH, and ACGIH Short Term Exposure Limits (STEL), and ceiling limits. A safety factor of 10 is universally applied to all short-term standards.

The next step was a dispersion analysis. Each source of pollutants (main boiler and auxiliary boiler) was modeled using the USEPA SCREEN3 model assuming an emission rate of 1 g/s. The model that resulted in the highest Maximum Ground Level Concentration (MGLC) was assumed to be the stack with the poorest dispersion. Table 6-1 below shows the results of this modeling for each of the sources.

Table 6-1 SCREEN3 Modeling Results Summary

Source ID	Source	Stack Height (m)	Stack Dia. (m)	Stack Velocity (m/s)	Stack Temp. (K)	1-Hour MGLC from SCREEN3 Analysis (μg/m^3)
MAIN	Coal Fired Boiler	137.16	9.14	18.55	333	0.698
AUX	Auxiliary Boiler	27.43	1.52	19.81	408	6.02

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

As shown, the Auxiliary Boiler was found to have the highest 1-hour MGLC. In order to determine the worst case ambient air concentration for each pollutant, it was assumed that the worst case emission rate for each toxic was emitted out of this stack. Following the Georgia guidelines, the 1-hour concentration for the actual emission rate from each toxic was determined by a direct ratio of emission rates. The 1-hour MGLC from the SCREEN3 model was adjusted to an annual, 24-hr continuous or short-term (15-min) concentration using the correction factors 0.08, 0.40, and 1.32, respectively. These annual and short-term MGLC's were then compared to the derived AACs and short-term limits. The results of this analysis are summarized in Table 6-2, which shows levels below the AACs for all compounds except hydrogen chloride, sulfuric acid, arsenic, and hexavalent chromium.

As per the Georgia guidelines, ISCST3 modeling was completed for these pollutants. The results of the analysis for the ISCST3 models are shown below in Table 6-3. The results of these models demonstrate compliance with the Georgia air toxics program.

Table 6-2 Toxic Emissions Summary

Pollutant	Main Boiler (g/s)	Auxiliary Boiler (g/s)	Total Emissions (lb/hr)	Total Emsission (g/s)	1-Hr MGLC (mg/m^3)	Annual MGLC (mg/m^3)	AAC Annual (mg/m^3)	% of allowable AAC	24-Hr MGLC (mg/m^3)	AAC 24-hour (mg/m^3)	% of allowable AAC	15-Min MGLC (mg/m^3)	Short (15-min) Term Limit (mg/m^3)	% of allowable Short Term Limit	Is Refined Modeling Required ?
Organics															
Acenaphthene	2.8E-05	4.49E-06	2.55E-04	3.22E-05	1.94E-07	1.55E-08	-	-	7.76E-08	0.04	1.87E-04 %	2.56E-07	-	-	NO
Acenaphthylene	1.4E-05	5.39E-08	1.08E-04	1.36E-05	8.21E-08	6.57E-09	-	-	3.28E-08	0.12	2.70E-05 %	1.08E-07	-	-	NO
Acetaldehyde	3.1E-02	0.00E+00	2.46E-01	3.10E-02	1.86E-04	1.49E-05	4.55E-03	0.33%	7.46E-05	-	-	2.46E-04	4.50	5.47E-03 %	NO
Acetophenone	8.1E-04	0.00E+00	6.47E-03	8.15E-04	4.91E-06	3.93E-07	-	-	1.96E-06	0.12	1.68E-03 %	6.48E-06	-	-	NO
Acrolein	1.58E-02	0.00E+00	1.25E-01	1.57E-02	9.49E-05	7.59E-06	2.00E-05	37.95%	3.80E-05	-	-	1.25E-04	0.02	0.55%	NO
Ammonia	6.43	0.00E+00	5.11E+01	6.43E+00	3.88E-02	3.10E-03	1.00E-01	3.10%	1.55E-02	-	-	5.12E-02	2.44	2.10%	NO
Anthracene	1.14E-05	2.60E-07	9.26E-05	1.17E-05	7.03E-08	5.62E-09	-	-	2.81E-08	4.76E-04	5.90E-03 %	9.28E-08	-	-	NO
Benzene	7.06E-02	4.56E-05	5.61E-01	7.06E-02	4.26E-04	3.40E-05	4.55E-04	7.49%	1.70E-04	-	-	5.62E-04	1.60	3.52E-02 %	NO
Benzo(a)anthracene	4.7E-06	8.54E-07	4.40E-05	5.55E-06	3.34E-08	2.67E-09	-	-	1.34E-08	4.76E-04	2.81E-03 %	4.41E-08	-	-	NO
Benzo(a)pyrene	2.1E-06	0.00E+00	1.64E-05	2.06E-06	1.24E-08	9.95E-10	-	-	4.97E-09	4.76E-04	1.04E-03 %	1.64E-08	-	-	NO
Benzo(b)fluoranthene	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	4.76E-04	-	0.00E+00	-	-	NO
Benzo(g,h,i)perylene	2.6E-06	4.81E-07	2.48E-05	3.13E-06	1.88E-08	1.51E-09	-	-	7.53E-09	6.21E-04	1.21E-03 %	2.49E-08	-	-	NO
Benzo(g,h,i)pyrene	1.5E-06	0.00E+00	1.16E-05	1.47E-06	8.83E-09	7.07E-10	-	-	3.53E-09	6.21E-04	5.69E-04 %	1.17E-08	-	-	NO
Benzo(b,k)fluoranthene	6.0E-06	3.15E-07	4.99E-05	6.29E-06	3.79E-08	3.03E-09	-	-	1.52E-08	4.76E-04	3.18E-03 %	5.00E-08	-	-	NO
Benzo(k)fluoranthene	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	4.76E-04	-	0.00E+00	-	-	NO
Benzyl chloride	3.8E-02	0.00E+00	3.02E-01	3.80E-02	2.29E-04	1.83E-05	-	-	9.16E-05	1.19E-02	0.77%	3.02E-04	0.50	6.05E-02 %	NO
Biphenyl	9.2E-05	0.00E+00	7.33E-04	9.23E-05	5.56E-07	4.45E-08	-	-	2.22E-07	2.38E-03	9.34E-03 %	7.34E-07	-	-	NO
bis(2-Ethylhexyl)phthalate	4.0E-03	0.00E+00	3.15E-02	3.96E-03	2.39E-05	1.91E-06	-	-	9.55E-06	0.01	8.02E-02 %	3.15E-05	1.00	3.15E-03 %	NO
Bromoform	2.1E-03	0.00E+00	1.68E-02	2.12E-03	1.28E-05	1.02E-06	7.00E-02	1.46E-05 %	5.10E-06	-	-	1.68E-05	-	-	NO
Butane	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	5.66	-	0.00E+00	-	-	NO
2-Butanone (MEK)	2.1E-02	0.00E+00	1.68E-01	2.12E-02	1.28E-04	1.02E-05	5.00	2.04E-06 %	5.10E-05	-	-	1.68E-04	88.47	1.90E-04 %	NO
Carbon disulfide	7.1E-03	0.00E+00	5.60E-02	7.06E-03	4.25E-05	3.40E-06	0.70	4.86E-06 %	1.70E-05	-	-	5.61E-05	9.33	6.02E-04 %	NO
Chlorobenzene	1.2E-03	0.00E+00	9.48E-03	1.19E-03	7.20E-06	5.76E-07	-	-	2.88E-06	0.83	3.45E-04 %	9.50E-06	-	-	NO
Chloroform	3.2E-03	0.00E+00	2.54E-02	3.20E-03	1.93E-05	1.54E-06	4.35E-04	0.36%	7.72E-06	-	-	2.55E-05	24.00	1.06E-04 %	NO
Chloromethane	2.9E-02	0.00E+00	2.28E-01	2.88E-02	1.73E-04	1.39E-05	-	-	6.94E-05	0.49	1.41E-02 %	2.29E-04	41.40	5.53E-04 %	NO
2-Chloroacetophenone	3.8E-04	0.00E+00	3.02E-03	3.80E-04	2.29E-06	1.83E-07	3.01E-05	0.61%	9.16E-07	-	-	3.02E-06	-	-	NO
Chrysene	5.4E-06	5.07E-07	4.71E-05	5.94E-06	3.58E-08	2.86E-09	-	-	1.43E-08	4.76E-04	3.00E-03 %	4.72E-08	-	-	NO
Cumene	2.9E-04	0.00E+00	2.28E-03	2.88E-04	1.73E-06	1.39E-07	0.40	3.47E-07 %	6.94E-07	-	-	2.29E-06	-	-	NO
Cyanide	1.4E-01	0.00E+00	1.08E+00	1.36E-01	8.18E-04	6.54E-05	-	-	3.27E-04	5.80E-04	56.41%	1.08E-03	-	-	NO
Dibenzo(a,h)anthracene	2.0E-06	3.56E-07	1.83E-05	2.31E-06	1.39E-08	1.11E-09	-	-	5.56E-09	4.76E-04	1.17E-03 %	1.84E-08	-	-	NO
Dichlorobenzene	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	1.07	-	0.00E+00	-	-	NO
Dimethyl sulfate	2.6E-03	0.00E+00	2.07E-02	2.61E-03	1.57E-05	1.26E-06	-	-	6.28E-06	1.19E-02	0.053%	2.07E-05	-	-	NO
7,12-Dimethylbenz(a)anthrace	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	4.76E-04	-	0.00E+00	-	-	NO
2,4-Dinitrotoluene	1.5E-05	0.00E+00	1.21E-04	1.52E-05	9.16E-08	7.33E-09	-	-	3.66E-08	3.57E-03	1.03E-03 %	1.21E-07	-	-	NO

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

Table 6-2 Toxic Emissions Summary (continued)

Pollutant	**Main Boiler (g/s)**	**Auxiliary Boiler (g/s)**	**Total Emissions (lb/hr)**	**Total Emission (g/s)**	**1-Hr MGLC (mg/m^3)**	**Annual MGLC (mg/m^3)**	**AAC Annual (mg/m^3)**	**% of allowable AAC**	**24-Hr MGLC (mg/m^3)**	**AAC 24-hour (mg/m^3)**	**% of allowable AAC**	**15-Min MGLC (mg/m^3)**	**Short (15-min) Term Limit (mg/m^3)**	**% of allowable Short Term Limit**	**Is Refined Modeling Required ?**
Ethane	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	2.93	-	0.00E+00	-	-	NO
Ethylbenzene	5.1E-03	1.35E-05	4.06E-02	5.12E-03	3.08E-05	2.47E-06	1.00	2.47E-06 %	1.23E-05	-	-	4.07E-05	54.27	7.50E-05 %	NO
Ethyl Chloride	2.3E-03	0.00E+00	1.81E-02	2.28E-03	1.37E-05	1.10E-06	10.00	1.10E-05 %	5.50E-06	-	-	1.81E-05	-	-	NO
Ethylene dichloride	2.2E-03	0.00E+00	1.72E-02	2.17E-03	1.31E-05	1.05E-06	-	-	5.23E-06	0.10	5.43E-03 %	1.73E-05	-	-	NO
Ethylene dibromide	6.5E-05	0.00E+00	5.17E-04	6.52E-05	3.93E-07	3.14E-08	-	-	1.57E-07	0.37	4.29E-05 %	5.18E-07	23.07	2.25E-06 %	NO
Fluoranthene	3.9E-05	1.03E-06	3.14E-04	3.96E-05	2.38E-07	1.91E-08	-	-	9.54E-08	0.01	1.38E-03 %	3.15E-07	-	-	NO
Fluorene	4.9E-05	9.52E-07	4.00E-04	5.04E-05	3.03E-07	2.43E-08	-	-	1.21E-07	4.76E-04	0.025%	4.01E-07	-	-	NO
Formaldehyde	3.86E-02	7.03E-03	3.62E-01	4.56E-02	2.75E-04	2.20E-05	7.69E-04	2.86%	1.10E-04	-	-	3.63E-04	0.25	0.15%	NO
Hexane	3.6E-03	0.00E+00	2.89E-02	3.64E-03	2.19E-05	1.75E-06	0.20	8.79E-04 %	8.77E-06	-	-	2.89E-05	352.47	8.21E-06 %	NO
Hydrogen chloride	65.17	0.00E+00	5.17E+02	6.52E+01	3.93E-01	3.14E-02	0.02	157.43%	1.57E-01	-	-	5.18E-01	0.70	74.03%	**YES**
Indeno(1,2,3,c,d)pyrene	3.3E-06	0.00E+00	2.63E-05	3.31E-06	2.00E-08	1.60E-09	-	-	7.98E-09	4.76E-04	1.68E-03 %	2.63E-08	-	-	NO
Isophorone	3.2E-02	0.00E+00	2.50E-01	3.15E-02	1.90E-04	1.52E-05	-	-	7.59E-05	0.33	0.023%	2.50E-04	2.83	8.86E-03 %	NO
Methyl Bromide	8.69E-03	0.00E+00	6.90E-02	8.69E-03	5.23E-05	4.19E-06	-	-	2.09E-05	9.24E-03	0.23%	6.91E-05	8.00	8.64E-04 %	NO
Methyl hydrazine	9.2E-03	0.00E+00	7.33E-02	9.23E-03	5.56E-05	4.45E-06	-	-	2.22E-05	-	-	7.34E-05	0.04	0.21%	NO
MMA	1.1E-03	0.00E+00	8.62E-03	1.09E-03	6.54E-06	5.23E-07	0.70	7.48E-05 %	2.62E-06	-	-	8.64E-06	40.95	2.11E-05 %	NO
2-Methylnaphthalene	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	6.93E-03	-	0.00E+00	-	-	NO
3-Methylchloranthrene	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	-	-	0.00E+00	-	-	NO
MTBE	1.9E-03	0.00E+00	1.51E-02	1.90E-03	1.15E-05	9.16E-07	3.00	3.05E-05 %	4.58E-06	-	-	1.51E-05	-	-	NO
Methylene chloride	1.6E-02	0.00E+00	1.25E-01	1.57E-02	9.49E-05	7.59E-06	1.33E-03	0.57%	3.80E-05	-	-	1.25E-04	43.38	2.89E-04 %	NO
Naphthalene	1.3E-03	2.41E-04	1.24E-02	1.56E-03	9.41E-06	7.53E-07	3.01E-03	2.50E-02 %	3.77E-06	-	-	1.24E-05	7.86	1.58E-04 %	NO
5-Methyl chrysene	1.2E-06	0.00E+00	9.48E-06	1.19E-06	7.20E-09	5.76E-10	-	-	2.88E-09	4.76E-04	0.00%	9.50E-09	-	-	NO
OCDD	3.6E-09	0.00E+00	2.88E-08	3.63E-09	2.18E-11	1.75E-12	-	-	8.74E-12	6.90E-02	1.27E-08 %	2.88E-11	-	-	NO
Phenanthrene	1.5E-04	2.24E-06	1.18E-03	1.49E-04	8.97E-07	7.17E-08	-	-	3.59E-07	4.76E-04	7.53E-02 %	1.18E-06	-	-	NO
Phenol	8.7E-04	0.00E+00	6.90E-03	8.69E-04	5.23E-06	4.19E-07	-	-	2.09E-06	4.52E-02	4.63E-03 %	6.91E-06	6.00	1.15E-04 %	NO
Propane	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	4.29	-	0.00E+00	-	-	NO
Propionaldehyde	2.1E-02	0.00E+00	1.64E-01	2.06E-02	1.24E-04	9.95E-06	-	-	4.97E-05	0.11	4.39E-02 %	1.64E-04	-	-	NO
Pyrene	1.8E-05	9.05E-07	1.49E-04	1.88E-05	1.13E-07	9.07E-09	-	-	4.54E-08	4.76E-04	9.53E-03 %	1.50E-07	-	-	NO
Styrene	1.4E-03	0.00E+00	1.08E-02	1.36E-03	8.18E-06	6.54E-07	-	-	3.27E-06	-	-	1.08E-05	85.20	1.27E-05 %	NO
Sulfuric Acid (H_2SO_4) [1]	5.23	0.00E+00	4.15E+01	5.23E+00	3.15E-02	2.52E-03	-	-	1.26E-02	2.38E-03	529.18%	4.16E-02	-	-	**YES**
Tetrachloroethylene	2.3E-03	0.00E+00	1.85E-02	2.34E-03	1.41E-05	1.13E-06	-	-	5.63E-06	1.61	3.49E-04 %	1.86E-05	135.60	1.37E-05 %	NO
Toluene	1.3E-02	1.32E-03	1.14E-01	1.44E-02	8.65E-05	6.92E-06	5.00	1.38E-04 %	3.46E-05	-	-	1.14E-04	113.10	1.01E-04 %	NO
1,1,1-Trichloroethane	1.1E-03	5.03E-05	9.02E-03	1.14E-03	6.85E-06	5.48E-07	-	-	2.74E-06	4.52	6.05E-05 %	9.04E-06	190.00	4.76E-06 %	NO
Vinyl acetate	4.1E-04	0.00E+00	3.28E-03	4.13E-04	2.49E-06	1.99E-07	0.20	9.97E-05 %	9.95E-07	-	-	3.28E-06	5.28	6.21E-05 %	NO
Xylene	2.0E-03	4.05E-05	1.63E-02	2.05E-03	1.23E-05	9.88E-07	0.10	9.73E-04 %	4.94E-06	-	-	1.63E-05	65.13	2.50E-05 %	NO

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

Table 6-2 Toxic Emissions Summary (continued)

Pollutant	Main Boiler (g/s)	Auxiliary Boiler (g/s)	Total Emissions (lb/hr)	Total Emission (g/s)	1-Hr MGLC (mg/m^3)	Annual MGLC (mg/m^3)	AAC Annual (mg/m^3)	% of allowable AAC	24-Hr MGLC (mg/m^3)	AAC 24-hour (mg/m^3)	% of allowable AAC	15-Min MGLC (mg/m^3)	Short (15-min) Term Limit (mg/m^3)	% of allowable Short Term Limit	Is Refined Modeling Required ?
Metals															
Antimony	9.78E-04	0.00E+00	7.76E-03	9.78E-04	5.89E-06	4.71E-07	-	-	2.36E-06	1.19E-03	0.20%	7.77E-06	-	-	NO
Arsenic	2.23E-02	1.19E-04	1.78E-01	2.24E-02	1.35E-04	1.08E-05	2.33E-07	4638.95%	5.39E-05	-	-	1.78E-04	2.00E-04	89.00%	YES
Barium	-	8.94E-05	7.10E-04	8.94E-05	5.39E-07	4.31E-08	4.90E-04	-	2.16E-07	-	-	7.11E-07	-	-	NO
Beryllium	1.14E-03	0.00E+00	9.05E-03	1.14E-03	6.87E-06	5.50E-07	4.17E-06	13.19%	2.75E-06	-	-	9.07E-06	-	-	NO
Cadmium	2.77E-03	8.94E-05	2.27E-02	2.86E-03	1.72E-05	1.38E-06	5.56E-06	24.80%	6.89E-06	-	-	2.27E-05	-	-	NO
Chromium, total	1.41E-02	8.94E-05	1.13E-01	1.42E-02	8.56E-05	6.85E-06	-	-	3.42E-05	2.38E-03	1.44%	1.13E-04	-	-	NO
Chromium, hexavalent	4.29E-03	0.00E+00	3.41E-02	4.29E-03	2.58E-05	2.07E-06	8.33E-08	2481.17%	1.03E-05	-	-	3.41E-05	-	-	YES
Cobalt	5.43E-03	0.00E+00	4.31E-02	5.43E-03	3.27E-05	2.62E-06	-	-	1.31E-05	2.38E-04	5.50%	4.32E-05	-	-	NO
Copper	9.83E-04	1.79E-04	9.22E-03	1.16E-03	7.00E-06	5.60E-07	-	-	2.80E-06	2.38E-04	1.18%	9.24E-06	-	-	NO
Lead	2.28E-02	2.68E-04	1.83E-01	2.31E-02	1.39E-04	1.11E-05	-	-	5.56E-05	1.19E-04	46.71%	1.84E-04	-	-	NO
Mercury	1.61E-03	8.94E-05	1.35E-02	1.70E-03	1.02E-05	8.17E-07	3.00E-04	0.27%	4.09E-06	-	-	1.35E-05	1.00E-02	0.13%	NO
Magnesium	5.97E-01	0.00E+00	4.74E+00	5.97E-01	3.60E-03	2.88E-04	-	-	1.44E-03	0.02	6.05%	4.75E-03	-	-	NO
Manganese	2.66E-02	1.79E-04	2.13E-01	2.68E-02	1.61E-04	1.29E-05	4.90E-05	26.35%	6.46E-05	-	-	2.13E-04	0.50	4.26E-02 %	NO
Molybdenum	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	3.57E-02	-	0.00E+00	-	-	NO
Nickel	1.52E-02	8.94E-05	1.21E-01	1.53E-02	9.21E-05	7.37E-06	-	-	3.69E-05	2.38E-03	1.55%	1.22E-04	-	-	NO
Selenium	7.06E-02	4.47E-04	5.64E-01	7.10E-02	4.28E-04	3.42E-05	-	-	1.71E-04	4.76E-04	35.95%	5.65E-04	-	-	NO
Vanadium	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-	-	0.00E+00	1.19E-04	-	0.00E+00	1.00E-02	-	NO
Zinc	6.55E-04	1.19E-04	6.15E-03	7.74E-04	4.67E-06	3.73E-07	-	-	1.87E-06	4.76E-03	3.92E-02 %	6.16E-06	1.00	6.16E-04 %	NO

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

Table 6-3 ISCST3 Toxics Modeling Results

Arsenic: Annual Average Period

Year of Model Run	**Maximum Concentration (μg/m^3)**	**Location of Receptors (UTM)**	
1974	5.00E-05	340137	3657911
1975	4.00E-05	333000	3660000
1976	5.00E-05	340137	3657811
1977	5.00E-05	333000	3660000
1978	5.00E-05	333000	3659500
Maximum Concentration: 5.00E-05 μg/m^3			
Allowable Concentration: 2.33E-04 μg/m^3			
% of Allowable AAC: 21.46 %			

Hexavalent Chromium: Annual Average Period

Year of Model Run	**Maximum Concentration (μg/m^3)**	**Location of Receptors (UTM)**	
1974	1.00E-05	340137	3657911
1975	1.00E-05	333000	3660000
1976	1.00E-05	340137	3657811
1977	1.00E-05	333000	3660000
1978	1.00E-05	333000	3659500
Maximum Concentration: 1.00E-05 μg/m^3			
Allowable Concentration: 8.33E-05 μg/m^3			
% of Allowable AAC: 12.00 %			

Hydrogen Chloride: Annual Average Period

Year of Model Run	**Maximum Concentration (μg/m^3)**	**Location of Receptors (UTM)**	
1974	0.098	341237	3662111
1975	0.084	332500	3660000
1976	0.091	342000	3656500
1977	0.099	333000	3660000
1978	0.103	332500	3659500
Maximum Concentration: 0.103 μg/m^3			
Allowable Concentration: 20 μg/m^3			
% of Allowable AAC: 0.52 %			

Sulfuric Acid: 24 Hour Average Period

Year of Model Run	**Maximum Concentration (μg/m^3)**	**Location of Receptors (UTM)**	
1974	0.295	336537	3660811
1975	0.371	338181	3659773
1976	0.277	340237	3661411
1977	0.295	336237	3659311
1978	0.302	336137	3659911
Maximum Concentration: 0.371 μg/m^3			
Allowable Concentration: 2.38 μg/m^3			
% of the Allowable AAC: 15.59 %			

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

7.0 CLASS I AREA MODELING

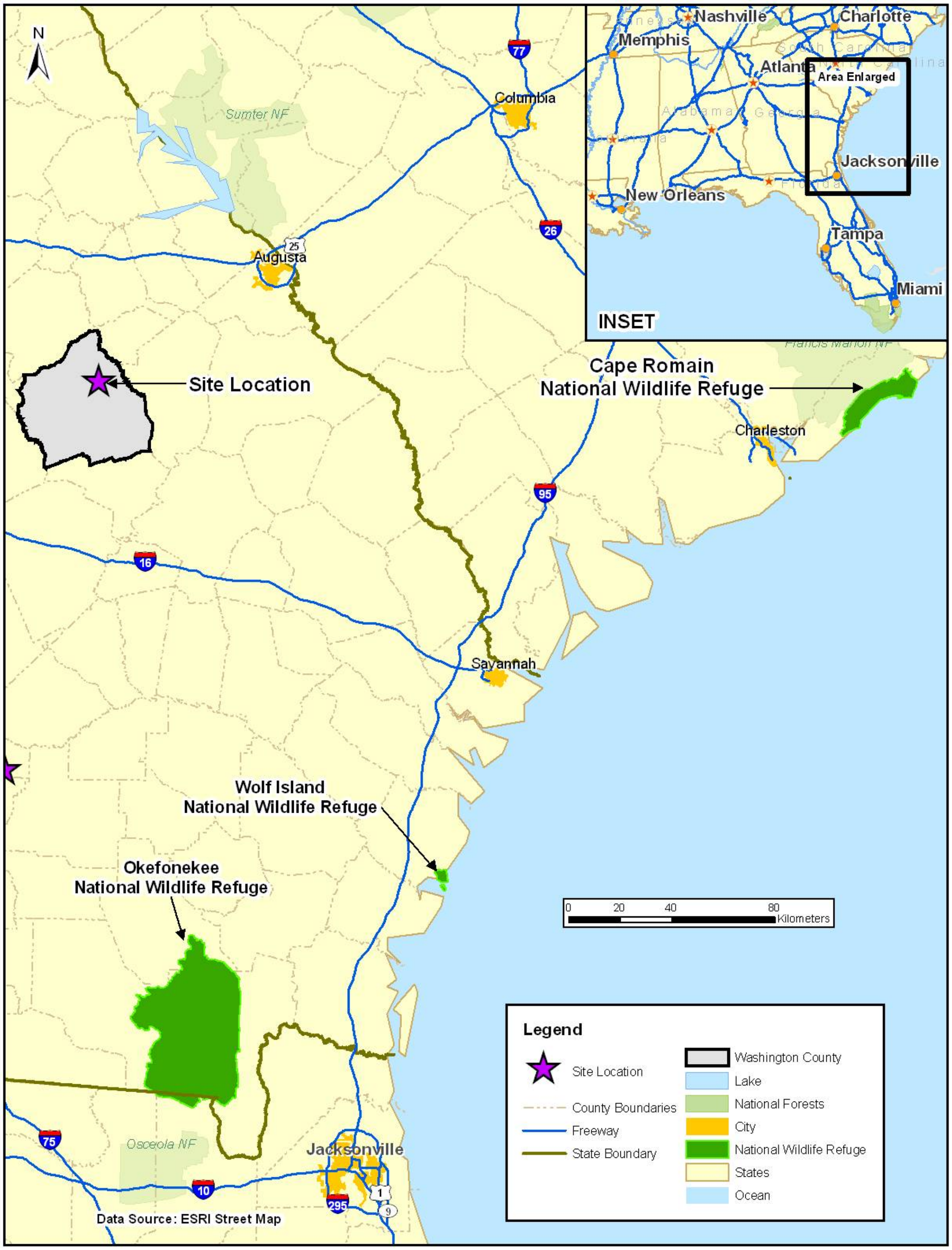
Plant Washington is located near several Class I areas. Table 7-1 below lists each Class I area and the distance to the point closest to Plant Washington. Figures 7-1 and 7-2 show the location of the Class I areas in relation to Plant Washington. The PSD permit coordinator with the Federal Land Manager (FLM) was contacted to determine the analysis that should be completed to assess the project's impact on these Class I areas. The PSD coordinator indicated that a visibility impairment analysis, a deposition analysis, and an initial screening analysis should be completed per the FLM Air Quality Related Values Workgroup (FLAG) Phase I document dated December 2000 to determine the proposed facility's impact on each of the Class I areas. The CALPUFF (version 5.8, level 070623) and CALPOST (version 5.6394, level 070622) models were used to complete this analysis.

Table 7-1 Class Area within 300 km Plant Washington

Class I Area	Distance to Plant Washington (km)
Cape Romain	289
Cohutta	261
Great Smokey Mnts	273
Joyce Kilmer	276
Shining Rock	252
Wolf Island	232
Okefenokee	228

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

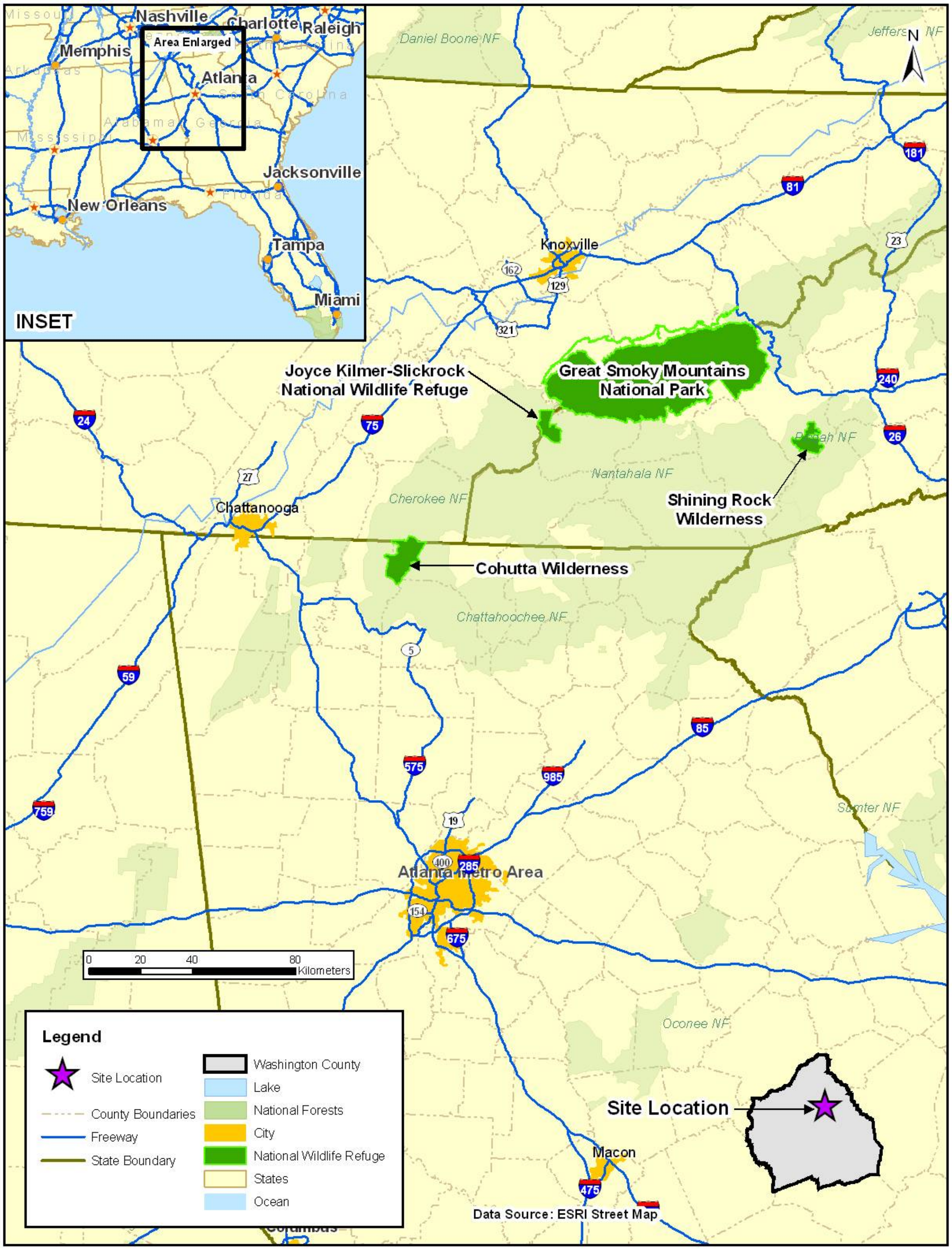
Figure 7-1 Relative Location Map of Site to the Class I Area



Data Source: ESRI Street Map

Prepared by: FC 1/17/08
Checked by: SAK 1/17/08

Figure 7-2 Relative Location Map of Site to the Class I Area



Data Source: ESRI Street Map

Prepared by: FC 1/17/08
Checked by: SAK 1/17/08

The CALPUFF modeling was completed using three years (2001 – 2003) of 4-kilometer grid meteorological data, which was provided by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) via South Carolina Department of Health and Environmental Control (SC DHEC). VISTAS generated the meteorological data in July 2007 using CALMET version 5.7. The receptor sets for the Class I areas were downloaded from the U.S. National Park Service (USNPS) web site and converted to the Lambert Conformal Conic (LCC) coordinate system, which is the coordinate system used by the VISTAS meteorological dataset. The National Park Service Convert Class 1 Areas program downloaded from the USNPS website was used to convert Plant Washington emission source UTM coordinates into the LCC coordinate system. In accordance with FLAG modeling documents, the modeling evaluation did not include building downwash because the Class I areas being evaluated are greater than 50 kilometers from the site.

To assess visibility impacts, the "method two" analysis was used. This method utilizes hourly relative humidity values generated from the CALMET data to calculate 24-hour average βextinction. In the CALPOST post processor, the MISBK parameter is set to 2, and the maximum relative humidity (RHMAX) is set to 95.0. The hourly relative humidity data was generated in the CALPUFF model as a "VIS.DAT" file and then utilized in the CALPOST post processor. The modeled species included in computing light extinction were sulfate, nitrate, and fine particulate, which were identified as PM_{10} in the model runs. Background extinction coefficients are computed for background sulfate and soil based on seasonal averaged hygroscopic and non-hygroscopic values found in Appendix 2 B of the FLAG document.

In the CALPUFF model, an emission rate for elemental carbon was estimated as 1% of the total PM, based on a report published by Pacific Environmental Services, Inc. dated September 29, 2003, and available on the USEPA Technology Transfer Network web site. This report evaluates speciation data of $PM_{2.5}$ emissions from coal fired boilers. The value of 1% is conservative since the value of 1% was derived from the total PM emissions, not the $PM_{2.5}$ emissions.

The CALPUFF model also has an input parameter for organic carbon (OC), processed as secondary organic aerosols (SOA) using the SOA module of CALPUFF. However, as discussed in the *Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART) (8/31/06)*, the developers (of CALPUFF) "view the SOA module as needing more testing and evaluation." The SOA module relies on the fact that only hydrocarbons with more than 6 carbon atoms can form significant SOA, and is best suited for evaluation of biogenic organics. This BART guidance document also discusses the default RH value of 98% of the CALPUFF model, and that the most common user selected value is 95% RH. The value of 95% RH was also selected for this assessment.

Table 7-2 presents the modeling results. As shown all results are below the 5% screening level established in the FLAG document as a level at which further evaluation is warranted.

Table 7-2 CALPUFF Method 2 Modeling Results for Class I Areas near Plant Washington

Class I Area	Model Year			Max. Result	Screen Level	Below Screen Level?
	2001	2002	2003			
Cape Romain	1.83%	3.16%	2.17%	3.16%	5%	Yes
Cohutta Wilderness	1.96%	1.77%	2.47%	2.47%	5%	Yes
Great Smokey Mountains	1.53%	1.22%	2.07%	2.07%	5%	Yes
Joyce Kilmer Slickrock	1.20%	0.73%	1.40%	1.40%	5%	Yes
Okefenokee	1.72%	2.02%	1.42%	2.02%	5%	Yes
Shining Rock	1.61%	1.22%	1.97%	1.97%	5%	Yes
Wolf Island	2.06%	2.41%	2.11%	2.41%	5%	Yes

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

The SO_2 and NO_x emissions increases from the project were used to estimate sulfur and nitrogen deposition impacts on the Class I modeling areas under review. The CALPUFF model was used to create the wet and dry flux data files, which were processed further using the POSTUTIL program to generate a deposition flux file. The flux file is processed using the CALPOST post processor in order to determine total nitrogen (N) and sulfur (S) deposition. The units of the fluxes are in $g/m^2/s$. The modeling results were compared to the Class I Deposition Analysis Thresholds (DATs) recommended by the Federal Land Manager of 0.01 kg/ha/yr N or S as specified in the "Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds" document posted on the National Park Service website dated August 2001. Exceedance of DAT does not necessarily indicate an adverse impact, but rather that additional analyses of deposition impacts may be requested. Values below the DAT indicate a level of impact that is considered insignificant. Table 7-3 presents the results from all three modeled years. As indicated the modeling results for the nitrogen and sulfur deposition analysis are below the thresholds except for a few that are slightly above the DAT levels.

Table 7-3 Class I Increment Deposition Results

Class I Area	N Increment Results kg/ha/yr			S Increment Results kg/ha/yr		
	2001	**2002**	**2003**	**2001**	**2002**	**2003**
Cape Romain	3.25E-03	2.45E-03	1.92E-03	1.21E-02	1.06E-02	8.58E-03
Cohutta Wilderness	3.01E-03	4.26E-03	4.07E-03	8.86E-03	1.40E-03	1.20E-02
Great Smokey Mountains	2.84E-03	2.80E-03	3.94E-03	9.11E-03	8.83E-03	1.14E-02
Joyce Kilmer Slickrock	2.84E-03	3.09E-03	3.42E-03	8.58E-03	9.24E-03	1.04E-02
Okefenokee	1.46E-03	1.50E-03	7.44E-04	5.36E-03	5.20E-03	2.83E-03
Shining Rock	2.95E-03	2.89E-03	4.57E-03	8.99E-03	9.08E-03	1.20E-02
Wolf Island	2.62E-03	1.69E-03	7.35E-04	9.78E-03	7.40E-03	4.83E-03

DAT Level: 0.01 kg/ha/yr

Completed by: LMG 1/17/08
Checked by: SAK 1/17/08

An initial screening analysis was done to determine whether Plant Washington will have a significant impact on the concentration of pollutants in the ambient air at the seven Class I areas under evaluation. The CALPUFF model included all emission sources at the proposed Plant Washington site (point and fugitive sources). The CALPUFF model created concentration data files, which were processed using the CALPOST post processor to determine the maximum concentration at all receptors within the Class I areas. Tables 7-4, 7-5, and 7-6 present the Class I screening analysis results for PM_{10}, SO_2 and NO_x respectively, for all averaging periods and for all three years of meteorological data. Each of the computed maximum concentrations for each pollutant's averaging periods was below their respective significant impact levels currently established by USEPA, except for the 24-hr concentration for SO_2 at Wolf Island. A refined SO_2 PSD increment modeling analysis for Wolf Island was therefore completed.

In accordance with FLM guidelines an emission database of all SO_2 increment consuming sources within 300 km of Wolf Island was created with data received from Florida Department of Environmental Protection, South Carolina Department of Health and Environmental Control and Georgia Environmental Protection Division. As is allowed for PSD increment modeling, some of the sources were modeled at their actual emissions based on their emission rates in the Georgia and National Emission Inventories (NEI). Because the CALPUFF model is unable to run with more than 200 emission sources at a time the emission sources were split into six groups of 200 or less. All of the individual models were then combined using the CALSUM utility. These results are summarized in Table 7-7 and as indicated the results are below the Class I PSD SO_2 increment levels.

Table 7-4 CALPUFF Class I PM_{10} Screening Analysis

Annual PM_{10} Screening Results

Class I Area	Model Year 2001	Model Year 2002	Model Year 2003	Max. Conc. (μg/m^3)	Screening Level (μg/m^3)	Below Screening Level?
Cape Romain	2.32E-03	2.53E-03	2.40E-03	2.53E-03	0.2	Yes
Cohutta Wilderness	1.35E-03	1.81E-03	1.84E-03	1.84E-03	0.2	Yes
Great Smokey Mountains	1.02E-03	1.12E-03	1.56E-03	1.56E-03	0.2	Yes
Joyce Kilmer Slickrock	9.88E-04	1.18E-03	1.44E-03	1.44E-03	0.2	Yes
Okefenokee	1.43E-03	1.65E-03	1.01E-03	1.65E-03	0.2	Yes
Shining Rock	1.35E-03	1.53E-03	1.87E-03	1.87E-03	0.2	Yes
Wolf Island	1.97E-03	2.11E-03	1.85E-03	2.11E-03	0.2	Yes

24-Hour PM_{10} Screening Results

Class I Area	Model Year 2001	Model Year 2002	Model Year 2003	Max. Conc. (μg/m^3)	Screening Level (μg/m^3)	Below Screening Level?
Cape Romain	2.77E-02	3.88E-02	4.23E-02	4.23E-02	0.3	Yes
Cohutta Wilderness	2.93E-02	2.90E-02	3.54E-02	3.54E-02	0.3	Yes
Great Smokey Mountains	2.43E-02	1.95E-02	4.09E-02	4.09E-02	0.3	Yes
Joyce Kilmer Slickrock	2.14E-02	1.81E-02	4.31E-02	4.31E-02	0.3	Yes
Okefenokee	3.63E-02	3.35E-02	2.62E-02	3.63E-02	0.3	Yes
Shining Rock	3.32E-02	3.19E-02	3.79E-02	3.79E-02	0.3	Yes
Wolf Island	3.45E-02	3.48E-02	5.70E-02	5.70E-02	0.3	Yes

Prepared by: LMG 1/17/08
Checked by: SAK 1/17/08

Table 7-5 CALPUFF Class I SO_2 Screening Analysis

Annual SO_2 Results

Class I Area	Model Year			Max. Conc. (µg/m^3)	Screening Level (µg/m^3)	Below Screening Level?
	2001	2002	2003			
Cape Romain	7.90E-03	7.83E-03	7.85E-03	7.90E-03	0.1	Yes
Cohutta Wilderness	3.97E-03	4.84E-03	4.57E-03	4.84E-03	0.1	Yes
Great Smokey Mountains	2.41E-03	2.37E-03	2.91E-03	2.91E-03	0.1	Yes
Joyce Kilmer Slickrock	2.41E-03	2.52E-03	2.78E-03	2.78E-03	0.1	Yes
Okefenokee	4.68E-03	5.10E-03	3.00E-03	5.10E-03	0.1	Yes
Shining Rock	3.67E-03	3.36E-03	4.42E-03	4.42E-03	0.1	Yes
Wolf Island	7.38E-03	8.10E-03	7.56E-03	8.10E-03	0.1	Yes

24-Hour SO_2 Results

Class I Area	Model Year			Max. Conc. (µg/m^3)	Screening Level (µg/m^3)	Below Screening Level?
	2001	2002	2003			
Cape Romain	0.109	0.16	0.15	0.16	0.2	Yes
Cohutta Wilderness	0.126	0.11	0.14	0.14	0.2	Yes
Great Smokey Mountains	9.91E-02	7.59E-02	8.24E-02	0.10	0.2	Yes
Joyce Kilmer Slickrock	7.41E-02	6.34E-02	6.56E-02	0.07	0.2	Yes
Okefenokee	0.11	0.11	0.10	0.11	0.2	Yes
Shining Rock	0.16	0.12	0.157	0.16	0.2	Yes
Wolf Island	0.18	0.18	0.30	0.30	0.2	No

3-Hour SO_2 Results

Class I Area	Model Year			Max. Conc. (µg/m^3)	Screening Level (µg/m^3)	Below Screening Level?
	2001	2002	2003			
Cape Romain	0.34	0.44	0.50	0.50	1	Yes
Cohutta Wilderness	0.57	0.74	0.50	0.74	1	Yes
Great Smokey Mountains	0.28	0.31	0.55	0.55	1	Yes
Joyce Kilmer Slickrock	0.28	0.26	0.30	0.30	1	Yes
Okefenokee	0.67	0.42	0.37	0.67	1	Yes
Shining Rock	0.41	0.36	0.60	0.60	1	Yes
Wolf Island	0.43	0.57	0.62	0.62	1	Yes

Prepared by: LMG 1/17/08
Checked by: SAK 1/17/08

Table 7-6 CALPUFF Class I NO_x Screening Analysis

Annual NO_X Increment Results						
	Model Year					
Class I Area	**2001**	**2002**	**2003**	**Max. Conc. (µg/m^3)**	**Screening Level (µg/m^3)**	**Below Screening Level?**
Cape Romain	1.05E-03	1.33E-03	1.19E-03	1.33E-03	0.1	Yes
Cohutta Wilderness	5.76E-04	1.08E-03	9.03E-04	1.08E-03	0.1	Yes
Great Smokey Mountains	3.65E-04	3.77E-04	5.16E-04	5.16E-04	0.1	Yes
Joyce Kilmer Slickrock	3.00E-04	4.18E-04	5.59E-04	5.59E-04	0.1	Yes
Okefenokee	8.53E-04	7.97E-04	5.28E-04	8.53E-04	0.1	Yes
Shining Rock	7.24E-04	6.06E-04	5.58E-04	7.24E-04	0.1	Yes
Wolf Island	1.37E-03	1.92E-03	1.70E-03	1.92E-03	0.1	Yes

Completed by: JDC 1/17/08
Checked by: SAK 1/17/08

Table 7-7 CALPUFF SO_2 PSD Increment Modeling Results for Wolf Island Class I Area

Averaging Period	**2nd High Concentrations (Except For Annual)**			**Class 1 PSD Increment (µg/m^3)**
	2001 (µg/m^3)	**2002 (µg/m^3)**	**2003 (µg/m^3)**	
3-hr	10.7	10.3	11.5	25.0
24-hr	3.4	3.5	3.5	5.0
Annual	0.0	0.0	0.0	2.0

Completed by: JDC 1/17/08
Checked by: SAK 1/17/08

8.0 OTHER IMPACT ANALYSIS

In addition to evaluating the project's air quality impacts, the permit application addresses other potential impacts. This included impacts on local Class II visibility, secondary impacts on soils and vegetation, demographic impacts, and construction impacts as required by the PSD guidelines. In addition, this evaluation includes an evaluation of the projects impact on water consumption as well as on green house gas (GHG) emissions.

8.1 CLASS II VISIBILITY

The proposed project's impacts on Class II visibility were evaluated as part of the permit application. Class II visibility analyses only have to be performed for Regional airports, state or national parks, or state historical sites located within 50 km of the source. The largest municipal airport within 50 km of the Plant Washington is Louisville Municipal Airport (approximately 35 km east of the site). A review of the area did not find any state or federal parks or state historical sites within 50 km of the site.

The VISCREEN visibility model was used to model the impacts from the plant's potential emissions. A Level I Analysis was initially done in order to provide a conservative estimate of plume visual impacts. These impacts would be larger than those calculated with more realistic input and modeling assumptions. To conduct a Level I analysis, VISCREEN is run by setting the observer distance equal to the closest sensitive receptor and on-site source (the plant) while using Level I defaults, and a worst-case meteorological condition of F class stability and a wind speed of 1.0 m/s. This worst-case meteorological condition is assumed to persist for 12 hours, with a wind direction that would transport the plume in the direction of the observer. The Level I Analysis found that Plant Washington's visibility impacts would exceed the screening threshold for the Class II Area, therefore a Level II VISCREEN Analysis was completed.

Level II Analysis determines the worst-day plume dispersion characteristic using the method described in the *Tutorial Package for the VISCREEN Model.* In order to conduct the Level II analysis, it is necessary to determine the dispersion condition (wind speed and stability class of the wind in the direction of the Class II area) that has a 1% cumulative frequency of occurrence. This 1% level is a conservative approach that is expected to represent the worst case dispersion condition. For this analysis, a 22.5° wind sector directed towards the sensitive area by 6-hour time block of each day is ranked in sequence of increasing value of sigma_z times the wind speed of the condition under evaluation. The variable *sigma* is the Pasquill-Gifford vertical diffusion coefficient for a given stability class and downwind distance along the stable plume trajectory. Pasquill-Gifford vertical diffusion coefficient values were obtained from the Handbook of Air Pollution Control and Engineering and Technology[1]. Figures 8-1 depicts the 22.5° wind sector directed towards Louisville Municipal Airport.

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[1] Mycock , John C., McKenna, John D., and Theodore, Louis. Handbook of Air Pollution Control Engineering and Technology. New York, NY: CRC Press, Inc., 1995 (Figure 4, pg 328).

Figure 8-1 22.5º Wind Sector Directed Towards Louisville Municipal Airport

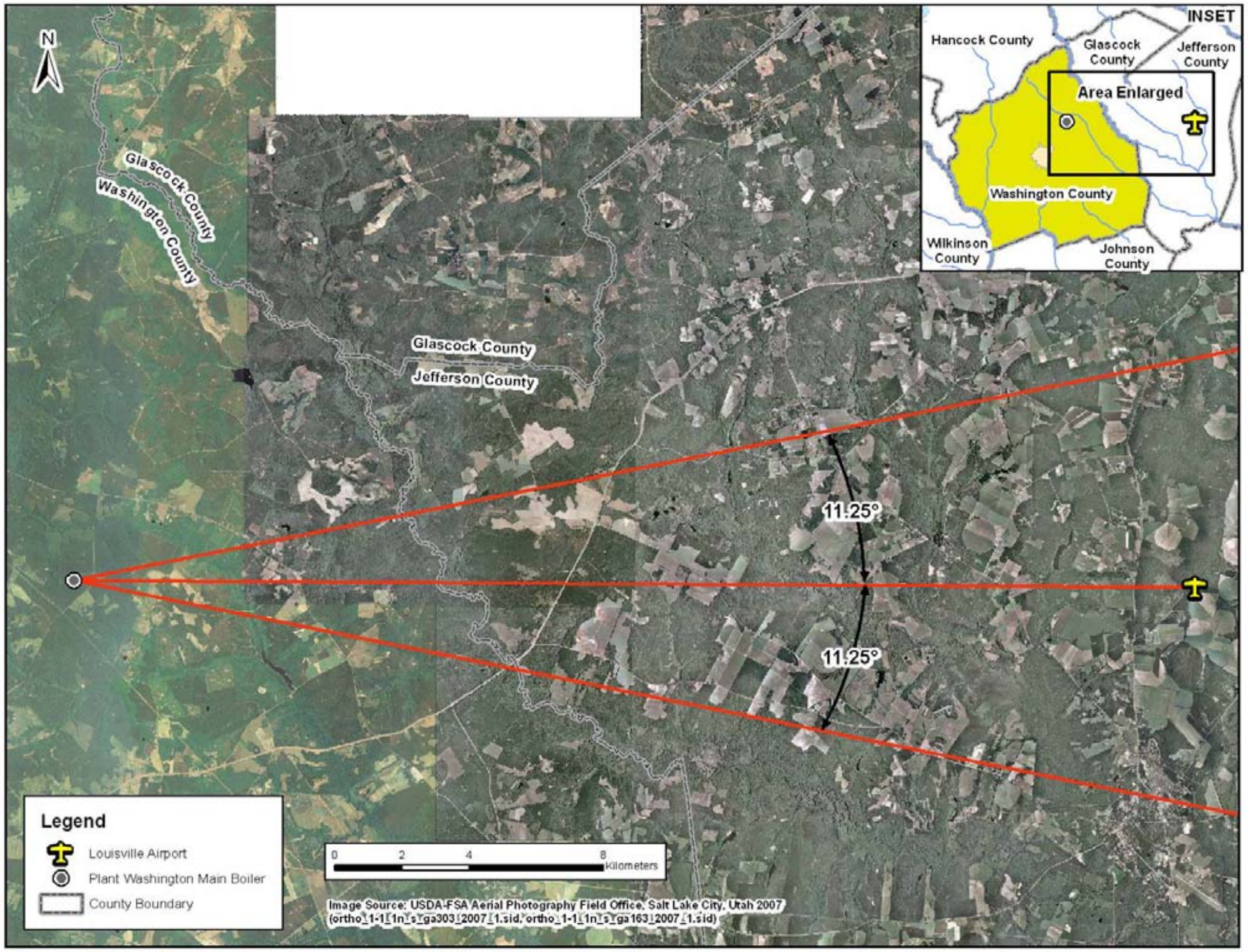

Image Source: USDA-FSA Aerial Photography Field Office, Salt Lake City, Utah 2007
(ortho_1-1_1n_s_ga303_2007_1.sid, ortho_1-1_1n_s_ga163_2007_1.sid)

Prepared by: FC 1/17/08
Checked by: JDF 1/17/08

For the Level II analysis, it is also assumed that steady state plume conditions will not persist for more than 12 hours because plume material would become more dispersed than a standard Gaussian plume model. Therefore, calms (time periods in the meteorological data where wind speeds are 0 m/s) were not evaluated.

Meteorological data files for surface data for the Macon Airport meteorological station and upper air data from the Centreville, Alabama meteorological station for 1974-1978 five-year period were obtained from the Georgia EPD website. Table 8-1 shows a summary table of the meteorological condition for each year that that has a 1% cumulative frequency of occurrence at Louisville Municipal Airport. Tables C-6 through C-10 in Appendix C show the results of this analysis for each 6-hour block of time within the five years of meteorological data to determine the dispersion condition that has a 1% cumulative frequency.

Table 8-1 Summary Table of Meteorological Conditions Resulting in a 1 Percent Cumulative Frequency of Occurrence at Louisville Municipal Airport

Year	**Meteorological Condition**	
	Stability Class	**Wind Speed**
1974	E	6
1975	D	4
1976	D	4
1977	D	4
1978	D	4

Prepared by: LMG 1/17/08
Checked by: SAK 1/17/08

The VISCREEN model was then run for these determined 1% worst case modeling conditions. The VISCREEN model results for these conditions indicate that the plume will not be visible at the airport. The Model runs for this Level II analysis are shown in Appendix D.

8.2 SECONDARY IMPACTS ON SOIL AND VEGETATION

PSD regulations require an assessment of other possible impacts, including any secondary impacts on soils and vegetation. An analysis was completed to assess the potential impact of vegetative stress in the area of the proposed plant as outlined in the USEPA document "A Screening Procedure for the Impact of Air Pollution sources on Plants, Soils, and Animals". This document provides ambient concentration levels of SO_2, NOx, CO, Fluorine, Beryllium and Lead which can be used for screening levels to determine if there is a potential for vegetative stress.

As a first step an intensive surveillance of the area surrounding the proposed plant site was conducted. The proposed plant is located in a rural area which is surrounded by wooded tracts and small farms. The vegetation present was identified and compared to the listing presented in the guidance document as being potentially sensitive to the compounds of concern (Tables B.1 through B.4 of the USEPA Screening document). No plant species were identified as being sensitive to nitrogen dioxide, however, there were species identified that are sensitive to sulfur dioxide and ozone. The area is in attainment with the ozone air quality standard and the proposed plant is not expected to change the attainment status of the area so the only species that could potentially be impacted are those identified as being sensitive for SO_2. The following is a listing of the sensitive vegetation found:

Crop Species sensitive to Sulfur Dioxide:

Blackberry (not a planted crop, only present as wild species)

Natural Vegetation sensitive to Sulfur Dioxide:

Ash
Tulip Tree (Tulip Poplar a.k.a. Yellow Poplar (liriodendeon tulipifera))
Black Willow

Some Natural Vegetation with Intermediate sensitivity to Sulfur Dioxide:

Boxelder
American Elm
White Oak

Some Natural Vegetation Resistant to Sulfur Dioxide:

Black gum
Dogwood
Red Oak
American Sycamore

Because vegetation is present that could potentially be stressed, an evaluation was completed using the modeled emissions calculated in the previous sections. Table 8-2 below summarizes the modeled concentrations for each pollutant and compares them to the screening level as taken from Table 3.1 of the USEPA screening procedure document. As indicated in Table 8-2, the maximum ground level concentrations for all pollutants for all averaging periods are well below the screening levels. With this demonstration it is apparent that not only is existing vegetation safe from potential vegetative stress but also any potential new crops that may be planted in the area will be as well.

Table 8-2 Screening Concentrations for Exposure to Ambient Air Concentrations

Pollutant	**Averaging Period**	**Basis**	**Modeled Result (µg/m3)**					**Maximum Modeled Result (µg/m3)**	**Background Concentration (µg/m^3)**	**Maximum Modeled Concentration plus Background (µg/m3) [6]**	**Screening Level (µg/m3)**	**Below Screening Level ?**
			1987	**1988**	**1989**	**1990**	**1991**					
SO$_2$	1-hr [1]	PSD Screening Modeling	49.7	50.9	45.3	42	38.8	50.9	225	276	917	Yes
	3-hr	PSD Screening Modeling	31.2	28.4	32.5	31.4	30.4	32.5	187	220	786	Yes
	Annual	PSD Screening Modeling	1.06	1.03	1.17	1.02	1.01	1.17	8	9	18	Yes
NOx	4 hr	PSD Screening Modeling	11.6	11.5	13.2	12.0	12.0	13.2	112	125	3760	Yes
	8 hr	PSD Screening Modeling	9.2	10.7	11.8	10.8	10.0	11.8	98.9	111	3760	Yes
	1 mo[2]	Conversion from PSD Screening Modeling	4.8	4.8	5.5	5.0	5.0	5.5	46.6	52.1	564	Yes
	1 yr	PSD Screening Modeling	0.59	0.57	0.65	0.57	0.56	0.65	11.3	12.0	94	Yes
CO[3]	1 wk	Conversion from PSD Screening Modeling	52.2	53.4	47.6	44.1	40.8	53.4	5,371	5,424	1,800,000	Yes
Fluorine[4,5]	10 days	Conversion from PSD Screening Modeling	0.019	0.018	0.018	0.018	0.018	0.019		0.019	0.5	Yes
Beryllium [2,7]	1 mo	Toxics Modeling	1.49E-04	1.52E-04	1.35E-04	1.06E-04	1.16E-04	1.52E-04	3.00E-05	1.82E-04	1.00E-02	Yes
Lead [8]	3 mo	PSD Screening Modeling	0.007	0.007	0.006	0.006	0.005	0.007	0.008	0.015	1.5	Yes

1. The 1-hour background concentration for SO$_2$ was calculated by dividing the 3-hour background concentration provided by the Georgia EPD by the 0.83 time averaging conversion factor for converting from 1 hr to 3 hr averages.

2. The AERMOD model does not allow for 1 month averaging modeling. The results from the 4-hour average modeling was converted to 1-hr average using the 0.79 conversion factor (1-hr to 4-hr) and then converted to a 1 month average using a 0.33 (1-hr to monthly) conversion factor. This factor was derived using the equation on page 55 of the EPA screening guidance.

3. The AERMOD model does not allow for 1 week averaging modeling. The results from the 1-hour average modeling was converted to the 7-day average using a 0.42 (1-hr to 7-day) conversion factor. This factor was derived using the equation on page 55 of the EPA screening guidance. The same value was used to convert the 1-hour background concentration data, which was provided by the Georgia EPD documentation "2006 Georgia Annual Air Quality Report."

4. The AERMOD model does not allow for 10 day averaging modeling. The results from the PSD screening completed for flourides was therefore converted to 10 day by using the 0.58 (1-hr to 24-hr) conversion factor to convert the results to 1 hour concentrations and then converted to 10 day results using the 0.39 (1-hr to 10-day) conversion factor. Both conversion factors come from Table A.2 from the EPA screening document.

5. No data was availible for the Fluorine background concentration.

6. The background SO$_2$ and NO$_X$ concentrations were provided by the Georgia EPD. The 1-hr concentration for SO$_2$ background was converted from the 3-hour background using the 0.83 time averaging conversion factor. The conversion factors from 1-hr to annual (0.08), from 1-hr to 4-hr (0.79), from 1-hr to 8-hr (0.70), and from 1-hr to monthly (0.33) were used to convert the NO$_X$ annual background to 4-hour and 8-hour averages.

7. Background concentration for beryllium based on the maximum result for all beryllium monitors in the state of Georgia for 2006. The AERMOD model does not allow for 1 month averaging modeling. The result from the 1-hour modeling was converted to 1 month averaging period modeling by using a conversion factor (0.33).

8. Background concentration for lead based on maximum result for the closest lead monitor to the site (Milledgeville) for 2006.

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Checked by: SAK 1/17/08

The USEPA Screening documents also outlines an evaluation for metals impacts. All these metals along with all other known toxics being emitted from the boiler were evaluated as part of the Georgia Air Toxics program in Section 7 of the permit application. The conclusion of that evaluation was that the plant demonstrates compliance with the Georgia toxics program, therefore, no further evaluation is being conducted in this section.

8.3 DEMOGRAPHICS

The proposed plant is expected to employ an estimated 100 to 150 people during operation. This workforce is expected to come from local communities, therefore, growth impacts are expected to be minimal and should not adversely affect the ambient air quality in the surrounding area. No additional automobile roadways are planned for the project.

8.4 CONSTRUCTION IMPACTS

During the construction phase of the proposed plant, there will be two primary sources of air emissions: 1) pollutants emitted from construction equipment and 2) fugitive dust emissions associated with the construction activities.

Typically, large gasoline and diesel powered construction equipment emit small amounts of VOCs, CO, SO_2, NO_x, and PM. Emissions due to the operation of this equipment are expected to cause only localized increases in pollutant levels. These increases will be only temporary and are not expected to cause any long-term adverse impacts on the construction area or the surrounding communities.

The fugitive dust emissions created from the construction activities will be more visible than the other pollutant emissions from the equipment. Site grading and preparation activities will create dust emissions. The greatest impact of the fugitive dust emissions will be confined to the construction site, and the effects on the surrounding properties are expected to be minimal. The extent of fugitive emissions will vary day to day, depending on the amount of construction activity and the weather. Standard engineering and construction practices will be implemented in order to minimize fugitive dust emissions (such as watering haul roads).

8.5 MINIMIZATION OF WATER USE

A coal-fired power plant like any other power generating facility burns fuel to produce electricity. This is accomplished by producing steam in a boiler and then having that steam pass through turbines which in turn generates electricity.

The plant will have three main uses of water: 1) boiler makeup and blowdown; 2) the flue gas desulfuring units (wet scrubbers); and 3) non-contact cooling. The water used to feed the boiler to produce steam is actually the smallest demand for water the plant since most of the steam is collected condensed and re-circulated back into the boiler. The only water required for this purpose is a relatively small amount of make-up water necessary to replace that lost in the steam handling process and for boiler blowdown. This is estimated to be approximately 120,000 gpd. The second highest demand for water is for operation of the wet scrubber that is used to remove SO_2 from the flue gases (wet flue gas desulfurization). There is a constant feed of water into this control device that replenishes the scrubant (pulverized slurried limestone) in the flue gas desulfuring units. Here, SO_2 reacts with the limestone to form gypsum ($CaSO_4$ 2HO). The amount of water used in this application is approximately 1.44 million gallons per day (mgd). The third (and largest) use will be for non-contact cooling water supplied to the cooling towers. Steam is condensed in the power generation process. The resulting condensate will be recirculated (recycled) back into the boiler to conserve heat and water. Steam itself can not be injected back into the boiler so it needs to be condensed back into water for that purpose. The heat generated from the condensing steam is dissipated in the cooling towers by evaporation of water. The cooling towers will use on the average approximately 12.6 MGD of water, of which approximately 10.8 MGD of water is will be evaporated in the cooling towers with the remainder being discharged to the river.

It should be noted that typical existing power plants use more water per unit of power generated than what is being proposed for this plant, which has a much more efficient design. Unfortunately the process of producing power does not convert all of the energy from burning the coal into electrical energy. Modern plants are only 31 to 34 percent efficient in the energy conversion process. The remainder portion of the heat is either vented out the stack or lost in the cooling tower. Plant Washington will be a supercritical unit that operates at much higher temperatures and pressures and consequently will be more efficient (estimated to be 36 to 39% efficient). This means that this plant will use approximately 15 percent less water than a comparable existing plant. Also consequently 15% less pollutants will be generated including green house gases on a per unit of power basis.

A potential technology exists that could further reduce water consumption called "dry cooling". In dry cooling steam is condensed by passing it through a finned heat exchanger similar to a radiator used in automobiles. Rather than cooling by evaporation the steam is condensed in heat exchangers which are cooled by blowing ambient across the fins and exhausting the sensible heat directly to the atmosphere. Dry cooling technology is not common and only a few such operations for coal fired generation plants are either being planned or under construction. None are currently operational so it is a technology yet to be demonstrated for this application. One such facility being planned is the Touquop Power Plant which is proposed to be built in Lincoln County Nevada. The proposed project consists of a supercritical unit similar to this project but of slightly smaller design (750 MW). A hybrid dry and wet cooling system is being proposed which would consist of a large hyperbolic cooling tower that encloses the fin radiators and air blowers. Due to the high temperature in the southwest during the summer months, the ambient air must be pre-cooled prior to being introduced into the cooling tower in order for the system to be effective. This cooling is accomplished using water sprays and consequently cools the air by evaporation. Approximately 2.5 million gallons per day is expected to be used for this purpose. So in this case 'dry cooling' means a reduction in water use, but not its elimination.

Dry cooling comes at a cost however. An engineering study was conducted to determine its feasibility for Plant Washington. The results of this study indicate that the use of a dry cooling system would result in a 41 to 44 MW reduction in the net output of the plant (due to the fact the system would cause back pressure on the turbines essentially de-rating their capabilities). In addition, these systems would add $142 to $148 million in capital system cost additions and $45 to $51 million in incremental operational and maintenance (O&M) cost. If actually installed this cost would have to be passed on to the customer increasing the power rate and the additional power lost by operating the system would be unavailable to customers and have to be generated elsewhere. If this 41 to 44 MW "lost power" were to be provided by another power plant or by increasing the size of Plant Washington even more air emissions would result (roughly equivalent to 34 TPY PM_{10}, 164 TPY SO_2, 92 TPY NO_x and 272 TPY CO). .

Power4Georgians takes seriously the need to conserve water in any operation. To that end a water conservation plan is being developed to look at recycling waste streams, utilize stormwater that falls on the site and to use mine dewatering water from local kaolin mines to reduce the consumption of surface water (from rivers) or groundwater. The overall plan is to use surface water when river flows are above a predetermined minimum level then switch to groundwater when river flows are below that cutoff point. In this way, surface water will only be used when there is adequate availability and groundwater will be used intermittently to avoid depletion of this resource.

8.6 GREENHOUSE GAS (GHG) MINIMIZATION

Coal fired power plants are major producers of GHG's primarily in the form of carbon dioxide. There is no proven technology that prevents this. The Department of Energy is currently funding a project that will attempt to inject the carbon dioxide back into the earth. This project called "Future Gen" is still undergoing permitting but if given the permission to proceed is scheduled to be on line in 2012. The pilot testing is expected to take another 5 years before conclusive results are found regarding the feasibility of this technology. Until this occurs other methods must be found to minimize the formation of GHG's. Power4Georgians being comprised of a consortium of member Georgia EMCs already have in place programs for their customers to conserve energy and in that way promote reduction of GHGs. These programs are ongoing and will become even more innovative as opportunities present themselves. The member companies see this opportunity to construct a new state-of-the-art power plant as being a part of a solution to the GHG problem by constructing a more efficient plant that will produce power that will emit less GHG on a per unit basis then existing comparable units. However, other options are also being developed. These options include: Carbon Footprint Reduction Program (CFRP), Home Energy Efficiency Program (HEEP), Solar Photovoltaic Program (SPVP), Carbon Sequestering Program (CSP) and others that are described below:

Carbon Footprint Reduction Program (CFRP)

Power4Georgians EMC will begin working with its customers to develop and implement a carbon footprint reduction program. The CFRP will be designed to help residential customers quantify their household carbon footprint and then provide those customers with the opportunity to reduce their carbon footprint through a number of programs, services and activities. The quantification of a customer's household carbon footprint will take into account the number of people living in the household, the amount of electricity, natural gas and fuel oil consumed in the house, the amount of waste produced within the house and the vehicular miles driven by members of the household and the average fuel economy of the vehicles. Once a customer quantifies their household carbon footprint, the CFRP program will offer a number of avenues to help the customer either reduce or possibly even eliminate their carbon footprint. These mechanisms include participating in Power4Georgians Carbon Sequestering Program (CSP), Power4Georgians EMC's Solar Photovoltaic Program (SPP), and/or Power4Georgians EMC's Carbon Sequestering Program (CSP).

Home Energy Efficiency Program (HEEP)

Customers can reduce the carbon footprint of their household energy consumption by implementing various energy efficiency projects in and around their home. Power4Georgians will develop informational sheets for the following energy efficiency measures: ceiling insulation, energy efficient windows, window film, caulking and weather-stripping, compact fluorescent lamps, programmable thermostats and high efficiency air conditioning and heat pump systems. Each measure will be quantified as its estimated reduction of carbon footprint. In addition, the customer's local EMC may offer or provide access to programs that provide financing for selected energy efficiency measures, including: ceiling insulation, energy efficient windows and high efficiency air conditioning and heat pump systems.

Solar Photovoltaic Program (SPP)

Customers can reduce the carbon footprint of their household energy consumption by satisfying a portion of their electrical usage with renewable solar energy. Power4Georgians EMC will work with the customer's local EMC to develop an incentive program for solar photovoltaic cells. The solar photovoltaic system will reduce consumption of electricity and thereby, reduce the home's carbon footprint.

Carbon Sequestering Program (CSP)

Customers will also be offered a carbon-sequestering program, which can be used to offset some or their entire carbon footprint. Power4Georgians CSP will provide an opportunity to invest in sustainable pine forests. Working in conjunction with customer's local EMC, Power4Georgians will offer customers the opportunity to buy blocks of trees in Georgia that are sustainable and will consume carbon produced by the household.

Beneficial Reuse of Fly Ash and Gypsum will reduce GHG from Cement and Wallboard Plant use

The Power4Georgians supports reuse of waste materials from our processes. Fly ash is a prominent component in the making of cement. Power4Georgians will retain and store fly ash on site for use by cement manufactures. Additionally, our process produces a gypsum product that can be used in the manufacture of wallboard or dry wall. We will retain these materials on site until a suitable partner can be found. Both of these efforts could reduce cement and gypsum manufactures from producing GHG in the production of like materials.

Reduction of Open Burning:

Power4Georgians will work with the Washington County Economic Development Authority and County Officials on the issue of open burning which contributes to particulate emissions in the area as well as GHG's. Potential ideas include spraying versus burning for forest brush clearing, landfill collection versus burning of leaves and other creative ideas.

Providing SE Georgia Firefighting Support to avert Wildfires

During 2007 wildfires in the Okefenokee national forest and other areas of southeast Georgia contributed immense quantities of particulate and GHG's to Georgia's air quality. Power4Georgians will contribute fire fighting equipment to the appropriate fire fighting departments for use in containing future fires in attempts to prevent such disasters from re-occurring.

Participation in Available Bio-Mass Projects

Some members of Power4Georgians will participate in the Yellow Pine Bio-Mass project that is expected to be built near Ft. Gaines, Georgia. When in commercial operation, this plant will produce approximately 110 MW of power using wood chips as the primary fuel source.

Develop Improvements in Technical Training and Emission Control

Power4Georgians will work with local technical schools to develop training programs that focus on environmental and emissions technology. In addition, Power4Georgians will work with

Georgia’s University System to establish a research program on improving emissions control technology.

9.0 GEORGIA EPD FORMS

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

SIP AIR PERMIT APPLICATION

EPD Use Only
Date Received: ______ Application No. ______

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: Plant Washington
AIRS No. (if known): 04-13- -
Facility Location: Street: Mayview Road
City: Sandersville Georgia Zip: 31082 County: Washington

2. Facility Coordinates

Latitude: 33° 03' 53" **NORTH** Longitude: 82° 44' 42" **WEST**
UTM Coordinates: 337088 **EAST** 3659816 **NORTH** **ZONE** 17

Facility Owner

Name of Owner: Power4Georgians, LLC
Owner Address Street: 258 N. Harris Street
City: Sandersville State: GA Zip: 31082

4. Permitting Contact and Mailing Address

Contact Person: Kip M. Fox or Brian A. Toole Title: Sr. Manager / Manager
Telephone No.: 770-763-4904 or 763-4922 Ext. ______ Fax No.: 770-763-4949
Email Address: KFox@ecg-llc.com or BToole@ecg-llc.com
Mailing Address: Same as: Facility Location: ☐ Owner Address: ☐ Other: ☒
If Other: Street Address: 3625 Cumberland Blvd., Suite 1525
City: Atlanta State: GA Zip: 30339

5. Authorized Official

Name: * See attached signature page Title: Management Committee Members
Address of Official Street: 258 N. Harris Street
City: Sandersville State: GA Zip: 31082

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

nature: ______________________ Date: ______________

SIGNATURE PAGE

Dwight Brown

Dwight Brown, Management Committee Member
Power4Georgians Management Committee
258 N. Harris Street
Sandersville, Georgia 31082 or
P.O. Box 598
Sandersville, Georgia 31082

Gary Miller

Gary Miller, Management Committee Member
Power4Georgians Management Committee
258 N. Harris Street
Sandersville, Georgia 31082 or
P.O. Box 598
Sandersville, Georgia 31082

Randall Pugh

Randall Pugh, Management Committee Member
Power4Georgians Management Committee:
258 N. Harris Street
Sandersville, Georgia 31082 or
P.O. Box 598
Sandersville, Georgia 31082

6. Reason for Application: (Check all that apply)

☒ New Facility (to be constructed)

☐ Existing Facility (initial or modification application)

☒ Permit to Construct

☒ Permit to Operate

☐ Change of Location

☐ Permit to Modify Existing Equipment: Affected Permit No.: ____

☐ Revision of Data Submitted in an Earlier Application

Application No.: ____

Date of Original Submittal: ____

7. Permitting Exemption Activities (for permitted facilities only):

Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?

☒ **No** ☐ **Yes, please fill out the SIP Exemption Attachment** (See Instructions for the attachment download)

8. Has assistance been provided to you for any part of this application?

☐ **No** ☐ **Yes, SBAP** ☒ **Yes, a consultant has been employed or will be employed.**

If yes, please provide the following information:

Name of Consulting Company: MACTEC Engineering and Consulting, Inc.

Name of Contact: Daniel A. Lovingood

Telephone No.: 770-499-6842 Fax No.: 770-421-3486

Email Address: DALOVINGOOD@mactec.com

Mailing Address: Street: 3200 Town Point Drive NW, Suite 100

City: Kennesaw State: GA Zip: 30144

Describe the Consultant's Involvement:

Prepared the Application

9. Submitted Application Forms: Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
2	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
1	2.02 Storage Tank Physical Data
0	2.03 Printing Operations
0	2.04 Surface Coating Operations
0	2.05 Waste Incinerators (solid/liquid waste destruction)
1	2.06 Manufacturing and Operational Data
1	3.00 Air Pollution Control Devices (APCD)
1	3.01 Scrubbers
1	3.02 Baghouses & Other Filter Collectors
0	3.03 Electrostatic Precipitators
5	4.00 Emissions Data
1	5.00 Monitoring Information
1	6.00 Fugitive Emission Sources
2	7.00 Air Modeling Information

0. Construction or Modification Date

Estimated Start Date: January 2009

11. If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?

☐ No ☐ Yes **N/A**

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	5,457	5,457
Nitrogen oxides (NOx)	1,836	1,836
Particulate Matter (PM)	705	705
PM <10 microns (PM10)	681	681
PM <2.5 microns (PM2.5)	377	377
Sulfur dioxide (SO_2)	3,279	3,279
Volatile Organic Compounds (VOC)	124	124
Total Hazardous Air Pollutants (HAPs)	See Attachment (Exhibit) A	See Attachment (Exhibit) A
Individual HAPs Listed Below:		
See Attachment (Exhibit) A		

13. Existing Facility Emissions Summary

Criteria Pollutant	Current Facility		After Modification	
	Potential (tpy)	Actual (tpy)	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)				
Nitrogen oxides (NOx)				
Particulate Matter (PM)				
PM <10 microns (PM10)				
PM <2.5 microns (PM2.5)				
Sulfur dioxide (SO_2)				
Volatile Organic Compounds (VOC)				
Total Hazardous Air Pollutants (HAPs)				
Individual HAPs Listed Below:				

14. 4-Digit Facility Identification Code:

SIC Code:	4911	SIC Description:	Electric Services - Electric Power Generation By Fossil Fuels
NAICS Code:	221112	NAICS Description:	Fossil Fuel Electric Power Generation

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

See Chapter 1 Introduction

16. Additional information provided in attachments as listed below:

Attachment A -	Emissions Calculations
Attachment B -	Site Layout
Attachment C -	Modeling Information
Attachment D -	Models
Attachment E -	
Attachment F -	

17. Additional Information: Unless previously submitted, include the following two items:

☒ Plot plan/map of facility location or date of previous submittal: See Attachment (Exhibit) B

☒ Flow Diagram or date of previous submittal: See Chapter 2 Process Description

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
MAIN	SCPC Boiler	Babcock-Wilcox variable pressure, once through, supercritical boiler with LNB (or equivalent)	Babcock-Wilcox variable pressure, once through, supercritical boiler with LNB & OFA
AUX	Auxiliary Boiler	TBD	Auxiliary Boiler for combustion of LS Diesel fuel. ~
COOL1-COOL34	Cooling Towers 1 - 34	TBD	Wet Cooling Towers list Ultra High Efficient Drift Eliminators.
CRUSH	Coal Crusher House	TBD	Coal Crusher House – enclosed with dust collection
LIMEPR	Limestone Preparation	TBD	Limestone Preparation House – enclosed with dust collection
ASHEXE	Ash Exhausters	TBD	Mechanical Fly Ash Exhausters (2)
FLYASH	Fly Ash Silo	TBD	Fly Ash Silo – equipped with bin vent filter
HGSILO	Hg Sorbent Silo	TBD	Hg Sorbent Silo – equipped with bin vent filter
SO3SILO	SO_3 Sorbent Silo	TBD	SO3 Sorbent Silo – equipped with bin vent filter
SODAASH	Soda Ash Silo	TBD	Soda Ash Silo – equipped with bin vent filter
LSILO	Lime Silo	TBD	Lime Silo – equipped with bin vent filter
CINSERT1	Coal Insert #1	TBD	Insertable Filter at coal unloading drop point
CINSERT2	Coal Insert #2	TBD	Insertable Filter at coal unloading drop point
LINSERT1	Limestone Insert #1	TBD	Insertable Filter at limestone unloading drop point

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 2.01 – BOILERS AND FUEL BURNING EQUIPMENT

Emission Unit ID	Type of Burner	Type of Draft[1]	Design Capacity of Unit (MMBtu/hr Input)	Percent Excess Air	Dates		Date & Description of Last Modification
					Construction	Installation	
MAIN	Wall Boiler with LNB/OFA	Induced	8300 MMBtu/hr	12	2012	2013	New Plant
AUX	LNB with FGR	unknown	240 MMBtu/hr	12	2012	2013	New Plant

[1] This column does not have to be completed for natural gas only fired equipment.

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season									
		Amount	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30	Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
MAIN	Coal	3,775,862	TPY	41.6%	59.3%	893,818	862,068	9286	9628	2.23	1.72	7.63	7.49
AUX	Low SulfurDiesel	4,643,000	Gal	41.6%	59.3%	530	530	140,000	140,000	0.05	0.05		

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Coal	TBD					
Diesel	TBD					

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 2.02 – ORGANIC COMPOUND STORAGE TANK

Emission Unit ID	Emission Unit Name	Capacity (gal)	Material Stored	Maximum True Vapor Pressure (psi @ °F)	Storage Temp. (°F)	Filling Method	Construction/ Modification Date	Roof Type	Seal Type
AUX	TNK1	350,000	Low Sulfur Diesel	See Tanks	Ambient	Submerged Fill	2012	Fixed Roof	TBD
Emergency Genset	TNK2	750	Low Sulfur Diesel	See Tanks	Ambient	Submerged Fill	2012	Fixed Roof	TBD
Fire Pump	TNK3	250	Low Sulfur Diesel	See Tanks	Ambient	Submerged Fill	2012	Fixed Roof	TBD

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 2.06 – MANUFACTURING AND OPERATIONAL DATA

rmal Operating Schedule: 24 hours/day 7 days/week 52 weeks/yr

Additional Data Attached? ☒ - No ☐ - Yes, please include the attachment in list on Form 1.00, Item 16.

Seasonal and/or Peak Operating Periods: N/A

Dates of Annually Occurring Shutdowns: TBD

PRODUCTION INPUT FACTORS

Emission Unit ID	Emission Unit Name	Const. Date	Input Raw Material(s)	Annual Input	Hourly Process Input Rate		
					Design	Normal	Maximum
MAIN	SCPC Boiler	2012	Coal	3,775,862 tpy	862,069 lbs/hr	862,069 lbs/hr	893,818 lbs/hr

PRODUCTS OF MANUFACTURING

Emission Unit ID	Description of Product	Production Schedule		Hourly Production Rate (Give units: e.g. lb/hr, ton/hr)			
		Tons/yr	Hr/yr	Design	Normal	Maximum	Units
MAIN	Electricity	N/A	N/A	850 Net	850 Net	850 Net	MW

Facility Name: Plant Washington **Date of Application:** 1/17/2008

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

APCD Unit ID	Emission Unit ID	APCD Type (Baghouse, ESP, Scrubber etc)	Date Installed	Make & Model Number (Attach Mfg. Specifications & Literature)	Unit Modified from Mfg Specifications?	Gas Temp. °F		Inlet Gas Flow Rate (acfm)
						Inlet	Outlet	
C01	MAIN	Baghouse	2012	TBD	No	320	300	2,579,088
C02	MAIN	SCR	2012	TBD	No	300	300	2,579,088
C03	MAIN	Wet Scrubber	2012	TBD	No	300	140	2,579,088
C04	SO3SILO	Bin Vent Filter	2012	TBD	No	68	68	1000
C05	FLYASH	Bin Vent Filter	2012	TBD	No	68	68	1000
C06	HGSILO	Bin Vent Filter	2012	TBD	No	68	68	1000
C07	LSILO	Bin Vent Filter	2012	TBD	No	68	68	1000
C08	CRUSH	Baghouse	2012	TBD	No	68	68	18000
C09	TRIP	Baghouse	2012	TBD	No	68	68	24000
C10	LIMEPR	Baghouse	2012	TBD	No	68	68	5000
C11	ASHEXH	Baghouse	2012	TBD	No	258	258	4812
C12	SODAASH	Bin Vent Filter	2012	TBD	No	68	68	1000
C13	CINSERT1	Insertable Filter	2012	TBD	No	68	68	1500
C14	CINSERT2	Insertable Filter	2012	TBD	No	68	68	1500
C15	LINSERT1	Insertable Filter	2012	TBD	No	68	68	1500

Facility Name: Plant Washington **Date of Application:** 1/17/2008

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency		Inlet Stream To APCD		Exit Stream From APCD		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
C01	PM10	99.9	99.9	14,900	Engr Est	149	Eng Est	12
C02	NOx	90	90	41,500	Engr Est	415	Eng Est	8-12
C03	SO2	97.5	97.5	74,700	Engr Est	747	Eng Est	10
C04	PM10	99.9	99.9	6	Engr Est	0.06	Eng Est	8
C05	PM10	99.9	99.9	6	Engr Est	0.06	Eng Est	8
C06	PM10	99.9	99.9	6	Engr Est	0.06	Eng Est	8
C07	PM10	99.9	99.9	6	Engr Est	0.06	Eng Est	8
C08	PM10	99.9	99.9	103	Engr Est	1.03	Eng Est	8
C09	PM10	99.9	99.9	77	Engr Est	0.77	Eng Est	8
C10	PM10	99.9	99.9	21	Engr Est	0.21	Eng Est	8
C11	PM10	99.9	99.9	10	Engr Est	0.10	Eng Est	8
C12	PM10	99.9	99.9	6	Engr Est	0.06	Eng Est	8
C13	PM10	99.9	99.9	6	Engr Est	0.06	Eng Est	8
C14	PM10	99.9	99.9	6	Engr Est	0.06	Eng Est	8
C15	PM10	99.9	99.9	6	Engr Est	0.06	Eng Est	8

Facility [illegible]me: Plant Washington **[illegible]ate of Application:** 1/17/2008

FORM 3.01 – SCRUBBERS

APCD Unit ID	Scrubber Type	Materials of Construction (Plastic, 1040 steel, etc.)	Scrubbant	pH Range	Pressure Drop Range (inches of H2O)	Minimum Scrubbant Flow Rate (Gal/min)	Is Scrubbant Recirculated?	Minimum Makeup Rate (Gal/min)	Size of Pond or Holding Tank (Acre-ft or gal)
C02	**SCR**	**TBD**	**NH3**			**TBD**	☐		
C02	**Wet Scrubber**	**TBD**	**Water**	**4.5-6.0**	**10**	**~200,000**	☒	1500	**1,500,000 gal**
							☐		
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Facility Name: Plant Washington **Date of Application:** 1/17/2007

FORM 3.02 – BAGHOUSES & OTHER FILTER COLLECTORS

APCD ID	Filter Surface Area (ft^2)	No. of Bags	Inlet Gas Dew Point Temp. (°F)	Inlet Gas Temp. (°F)	Bag or Filter Material	Pressure Drop (inches of water)	Cleaning Method	Gas Cooling Method	Leak Detection System Type
C01	TBD	32,000	280	320	TBD	12	PJ	TBD	Pressure Drop

Attach a physical description, dimensions and drawings for each baghouse and any additional information available such as particle size, maintenance schedules, monitoring procedures and breakdown/by-pass procedures. Explain how collected material is disposed of or utilized. Include the attachment in the list on Form 1.00 *General Information*, Item 16

Facility [illegible]ne: Plant Washington **Date of Application:** 1/17/2008

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
MAIN	C01,02, 03	S01	PM	149	149	654	654	BACT
MAIN	C01,02, 03	S01	PM_{10}	149	149	654	654	BACT
MAIN	C01,02, 03	S01	SO_2	996	996	3272	3272	BACT
MAIN	C01,02, 03	S01	H_2SO_4	42	42	182	182	BACT
MAIN	C01,02, 03	S01	HF	2.49	2.49	10.9	10.9	BACT
MAIN	C01,02, 03	S01	Pb	0.14	0.14	0.61	0.61	BACT
MAIN	C01,02, 03	S01	NO_X	415	415	1818	1818	BACT
MAIN	C01,02, 03	S01	VOC	28.22	28.22	124	124	BACT
MAIN	C01,02, 03	S01	CO	2490	2490	5453	5453	BACT
MAIN	C01,02,03	S01	Hg	0.014	0.014	0.06	0.06	BACT
AUX	--	S45	PM	0.48	0.48	2.10	2.10	BACT
AUX	--	S45	PM_{10}	0.48	0.48	2.10	2.10	BACT
AUX	--	S45	SO_2	12	12	5.26	5.26	BACT
AUX	--	S45	H_2SO_4	0.01	0.01	6.31E-03	6.31E-03	BACT
AUX	--	S45	Pb	2.16E-03	2.16E-03	9.46E-04	9.46E-04	BACT
AUX	--	S45	NO_X	24	24	10.51	10.51	BACT
AUX	--	S45	Hg	7.19E-05	7.19E-05	3.15E-04	3.15E-04	BACT

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
AUX	--	S45	VOC	0.72	0.72	0.32	0.32	BACT
AUX	--	S45	CO	2.02	2.02	0.88	0.88	BACT
COOL1-COOL34	--	S02-S35	PM	3.72	3.72	16.28	16.28	BACT
COOL1-COOL34	--	S02-S35	PM_{10}	1.71	1.71	7.51	7.51	BACT
CRUSH	C08	S40	PM	1.03	1.03	4.51	4.51	BACT
CRUSH	C08	S40	PM_{10}	1.03	1.03	4.51	4.51	BACT
TRIP	C09	S41	PM	0.77	0.77	3.38	3.38	BACT
TRIP	C09	S41	PM_{10}	0.77	0.77	3.38	3.38	BACT
LIMEPR	C09	S42	PM	0.21	0.21	0.94	0.94	BACT
LIMEPR	C09	S42	PM_{10}	0.21	0.21	0.94	0.94	BACT
ASHEX	C11	S43	PM	0.10	0.10	0.45	0.45	BACT
ASHEX	C11	S43	PM_{10}	0.10	0.10	0.45	0.45	BACT

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
FLYASH	C05	S37	PM	0.06	0.06	0.28	0.28	BACT
FLYASH	C05	S37	PM_{10}	0.06	0.06	0.28	0.28	BACT
HGSILO	C06	S38	PM	1.61E-02	0.06	7.04E-02	7.04E-02	BACT
HGSILO	C06	S38	PM_{10}	1.61E-02	0.06	7.04E-02	7.04E-02	BACT
SO3SILO	C04	S36	PM	1.61E-02	0.06	7.04E-02	7.04E-02	BACT
SO3SILO	C04	S36	PM_{10}	1.61E-02	0.06	7.04E-02	7.04E-02	BACT
SODAASH	C12	S44	PM	8.04E-03	8.04E-03	3.52E-02	3.52E-02	BACT
SODAASH	C12	S44	PM_{10}	8.04E-03	8.04E-03	3.52E-02	3.52E-02	BACT
LSILO	C07	S39	PM	8.04E-03	8.04E-03	3.52E-02	3.52E-02	BACT
LSILO	C07	S39	PM_{10}	8.04E-03	8.04E-03	3.52E-02	3.52E-02	BACT
CINSERT1	C13	S46	PM	0.06	0.06	0.26	0.26	BACT
CINSERT1	C13	S46	PM_{10}	0.06	0.06	0.26	0.26	BACT

Facilit me: Plant Washington **Date of Application:** 1/17/2008

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
CINSERT2	C14	S47	PM	0.06	0.06	0.28	0.28	BACT
CINSERT2	C14	S47	PM_{10}	0.06	0.06	0.28	0.28	BACT
LINSERT1	C15	S48	PM	0.06	0.06	0.28	0.28	BACT
LINSERT1	C15	S48	PM_{10}	0.06	0.06	0.28	0.28	BACT
BASH	--	F01	PM	1.27E-02	1.27E-02	5.56E-02	5.56E-02	AP-42
BASH	--	F01	PM_{10}	6.01E-03	6.01E-03	0.03	0.03	AP-42
LFASH	--	F02	PM	0.39	0.39	1.73	1.73	AP-42
LFASH	--	F02	PM_{10}	0.08	0.08	0.33	0.33	AP-42
LFGYP	--	F03	PM	0.39	0.39	1.73	1.73	AP-42
LFGYP	--	F03	PM_{10}	0.08	0.08	0.33	0.33	AP-42
LRAIL	--	F04	PM	1.0E-03	1.0E-03	4.39E-03	4.39E-03	AP-42
LRAIL	--	F04	PM_{10}	0.0005	0.0005	2.08E-03	2.08E-03	AP-42

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
CRAIL	--	F05	PM	6.21E-03	6.21E-03	2.72E-02	2.72E-02	AP-42
CRAIL	--	F05	PM_{10}	0.003	0.003	0.01	0.01	AP-42
LPILE	--	F06	PM	0.3152	0.3152	1.34	1.34	AP-42
LPILE	--	F06	PM_{10}	0.251	0.251	1.34	1.34	AP-42
IPRB	--	F07	PM	0.47	0.47	2.05	2.05	AP-42
IPRB	--	F07	PM_{10}	0.47	0.47	2.05	2.05	AP-42
IILL6	--	F08	PM	0.47	0.47	2.05	2.05	AP-42
IILL6	--	F08	PM_{10}	0.47	0.47	2.05	2.05	AP-42
APRB	--	F09	PM	0.471	0.471	2.06	2.06	AP-42
APRB	--	F09	PM_{10}	0.23	0.23	1.01	1.01	AP-42
AILL6	--	F10	PM	0.471	0.471	2.06	2.06	AP-42
AILL6	--	F10	PM_{10}	0.23	0.23	1.01	1.01	AP-42
HAULRD	--	F11-F31	PM	0.12	0.12	0.55	0.55	AP-42
HAULRD	--	F11-F31	PM_{10}	0.12	0.12	0.55	0.55	AP-42

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 5.00 MONITORING INFORMATION

Emission Unit ID/ APCD ID	Emission Unit/APCD Name	Monitored Parameter		Monitoring Frequency
		Parameter	Units	
S01	SCPC Boiler	NOx	PPM	CEM
S01	SCPC Boiler	SO2	PPM	CEM
S01	SCPC Boiler	CO	PPM	CEM
S01	SCPC Boiler	Hg	PPM	CEM
MISC	PM Transfer Points	VE	% Opacity	Quarterly
S2-S35	Cooling Tower	TDS		Quarterly

Comments:

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 6.00 – FUGITIVE EMISSION SOURCES

ugitive Emission Source ID	Description of Source	Emission Reduction Precautions	Pot. Fugitive Emissions	
			Amount (tpy)	Pollutant
F01	Bottom Ash Storage/Handling	Contouring, Compaction, Stabilization & Cover	5.56E-02	PM
F02	Ash Solid Materials Handling Facility	Contouring, Compaction, Stabilization & Cover	1.73	PM
F03	Gypsum Solid Materials Handling Facility	Contouring, Compaction, Stabilization & Cover	1.73	PM
F04	Limestone Rail Unloading	Partial Enclosure & Water Spray	<0.01	PM
F05	Coal Rail Unloading	Partial Enclosure & Water Spray	<0.01	PM
F06	Limestone Storage/Handling	Lowering Well & Water Spray	1.06	PM
F07	Inactive PRB Coal Pile Storage/Handling	Cover & Best Management Practices	8.21	PM
F08	Inactive ILL6 Coal Pile Storage/Handling	Cover & Best MAnagement Practices	8.21	PM
F09	Active PRB Coal Pile	Retractable Chute, Water Spray, Crusting agents, Contouring	2.06	PM
F10	Active ILL6 Coal Pile	Retractable Chute, Water Spray, Crusting agents, Contouring	2.06	PM
F11-F23	Solid Materials Handling Facility Haul Road Segments (for modeling)	Road Paving & Water Spray/Surfactants	0.55	PM

Facility Name: Plant Washington **Date of Application:** 1/17/2008

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm)	
									Average	Maximum
S1	MAIN	450	30	VERT	292	203	60.84	140	2,579,088	
S2-S35	COOL1-COOL34	50	40	VERT	292	203	19.92	68	1,501,171	
S36	SO3SILO	75	1.46	HORZ	292	203	10	68	1000	
S37	FLYASH	155	1.46	HORZ	292	203	75	177	7500	
S38	HGSILO	75	1.46	HORZ	292	203	10	68	1000	
S39	LSILO	75	1.46	HORZ	292	203	10	68	1000	
S40	CRUSH	100	3	VERT	292	203	56.59	68	24000	
S41	TRIP	194	2.583	VERT	292	203	57.25	68	18000	
S42	LIMEPR	60	1.46	HORZ	292	203	50	68	5000	
S43	ASHEXH	155	0.833	HORZ	292	203	73.6	258	4812	
S44	SODAASH	75	1.46	HORZ	292	203	10.	68	1000	
S45	AUXBOIL	90	5	VERT	292	203	65	275	76,538	
S46	CINSERT 1	110	TBD	HORZ	292	203	Modeled as 0.00328	68	1500	

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

- Horizontal sources were modeled with a velocity of 0.00328 ft/sec per modeling guidance, a corresponding flow rate was calculated for modeling purposes.
- Actual velocities are listed herein.

Facility Name: Plant Washington **Date of Application:** 1-17-2008

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm)	
									Average	Maximum
S47	CINSERT 2	90	TBD	HORZ	292	203	Modeled as 0.00328	68	1500	1500
S48	LINSERT1	70	TB	HORZ	292	203	Modeled as 0.00328	68	1500	1500

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

- Horizontal sources were modeled with a velocity of 0.00328 ft/sec per modeling guidance, a corresponding flow rate was calculated for modeling purposes.
- Actual velocities are listed herein.

Facility Name: Plant Washington **Date of Application:** ____________

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

Chemical	Potential Emission Rate (lb/hr)	Toxicity	Reference	MSDS Attached
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General Sandersville/Washington County Information

County Organization

Washington County Board of Commissioners
P.O. Box 271 – Courthouse Square
Sandersville, Georgia 31082
Phone: 478-552-2325
Fax: 478-552-7424

City Mayor

Mayor James W. (Jimmy) Andrews
738 W. Church St.
Sandersville, Georgia 31082
478-552-5480

Mayor Pro Tem Jeffery T. Smith
220 E. Church St.
Sandersville, Georgia 31082

Draft/Public Review Contact

S. Lee Lord, Clerk
Washington County Board of Commissioners
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County Board of Commissioners

Mr. Horace M. Daniel – Chairman
P.O. Box 271 – Courthouse Square
Sandersville, Georgia 31082
Phone: 478-552-2325
Fax: 478-552-7424

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