Application for
Prevention of Significant Deterioration Permit
for the Desert Rock Energy Facility

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Desert Rock Energy Facility

Application for

Prevention of Significant Deterioration Permit

Submitted to

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Air Division

San Francisco, California

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1.0 INTRODUCTION

1.1 Project Overview

Steag Power, LLC (Steag) is proposing a state-of-the-art; mine-mouth coal-fired power plant on Navajo Nation land. The green-field power plant will be of the supercritical pulverized coal type and will be designed for a total generation capacity of 1,500 MW (gross), made up of two separate units, each of which will produce 750 MW gross. Due to the selected location, coal will be delivered via a closed above ground conveyor belt from the crushing/blending facilities at the BHP mine. The facility will also include three auxiliary boilers, two emergency diesel generators and two diesel firewater pumps.

The project will use two dry natural draft Heller cooling tower systems because water is a critical resource in the region. Water for plant operations will be supplied from either the Navajo Agricultural Products Industry (NAPI) irrigation system or Morgan Lake. The currently preferred option is to draw makeup water from Morgan Lake located between Shiprock and Farmington, south of the San Juan River. Water rights are owned by BHP, the coal provider. This facility has been designed to optimize the use of water for power generation and to maximize efficiency of the plant operations.

The plant is in the Western Electricity Coordinating Council (WECC) grid and the power transmission interconnecting point will be in accordance with the results of the Navajo Transmission Project study (NTP). The generated power will serve local markets as well as markets in the Desert Southwest, Arizona and California.

Steag is scheduled to start construction on the first unit in 2005 in order to achieve commercial operation of the first unit in 2008. The construction of the second unit is scheduled to follow the first with less than a one-year lag.

The plant will employ over 200 permanent workers and up to a peak of 3,000 workers during the three years of construction. Workers are expected to come from within rural areas of the Navajo Nation (~10%), most will commute from Farmington or Shiprock (~60%), and the remainder from Gallup and Window Rock (~30%). Navajo Nation requires preferred employment of local people, thus automatically limiting growth in the area and reducing unemployment.

Since the proposed facility will be a “major source” of criteria air pollutants, Steag is applying for a Prevention of Significant Deterioration (PSD) permit. Because this project will be located on the Navajo Nation, and since the Navajo Nation does not yet have PSD delegation, this application is being submitted to the U. S. Environmental Protection Agency (EPA), in Region IX.

1.2 Facility Classification

There are two major classification criteria for the proposed facility, one related to its industrial character and the other to its potential to emit air contaminants. The designation of the facility under each of these is reviewed below.

1.2.1 Standard Industrial Classification (SIC) Code

The United States government has devised a method for grouping all business activities according to their participation in the national commerce system. The system is based on classifying activities into "major groups" defined by the general character of a business operation. For example, electric, gas, and sanitary services, which include power production, are defined as a major group. Each major group is given a unique two-digit number for identification. Power production activities have been assigned a major group code “49”.

To provide more detailed identification of a particular operation, an additional two-digit code is appended to the major group code. In the case of power generation facilities the two digit code is “11” in order to define the type of production involved. Thus, the Desert Rock Energy Facility is classified under the SIC code system as:

- “Major Group” 49 – “Electric, Gas, and Sanitary Services”
- Electric Services – 4911

The SIC Code system will eventually be replaced by North American Industrial Classification System (NAICS). This system's organization is similar to the SIC codes. Under this system, this facility would be classified under 221112, Fossil Fuel Electric Power Generation.

1.2.2 Air Quality Source Designation

With respect to air quality, new and existing industrial sources are classified as either major or minor sources based on their potential-to-emit (PTE) air contaminants. This classification is also affected in part by whether the area in which the source is located has attained the National Ambient Air Quality Standards (NAAQS) [1]. An area is classified as attainment if the ambient air quality concentration for a specific pollutant as measured by a monitor is below the standard concentration level for a set averaging period. The area in which the project is proposed to be located is designated as attainment for all the NAAQS.

[1] Criteria pollutants are those for which EPA has established NAAQS and consist of particulate matter with a nominal aerodynamic diameter of 10 microns or less and 2.5 microns or less, carbon monoxide, nitrogen dioxide, sulfur dioxide, lead and ozone, which is formed through the photochemical reaction of volatile organic compounds and oxides of nitrogen in the atmosphere.

For most activities, a major source is defined as one which has the potential-to-emit 250 tons per year (tpy) of any regulated air contaminant. For a special group of 28 industrial categories, the EPA has defined the major source emission threshold to be 100 tpy. Steam-Electric Power Generation is one of these special categories. Since, as will be shown in Section 5.0, potential emissions from the proposed facility will exceed the major source thresholds for Oxides of Nitrogen (NO_x), Carbon Monoxide (CO), Particulates (PM/PM_{10}), Volatile Organic Compounds (VOC), Sulfur Dioxide (SO_2), and Hazardous Air Pollutants (HAP), the project will be classified as a “major stationary source” of air emissions.

1.3 Document Organization

This application addresses the permitting requirements of the federally mandated program for PSD review (40 CFR 52.21) for a new major source. Section 2.0 provides an overview of the proposed project and the processes covered by this application. Section 3.0 discusses the regulatory setting for the project. Section 4.0 provides the control technology evaluation for those pollutants subject to PSD review. Section 5.0 presents the emissions anticipated from the operation of the facility. Section 6.0 presents a detailed discussion of the dispersion modeling methodology and applicable standards to which these predicted impacts are compared. Finally Section 7.0 references the regulatory and technical citations used in the document. Attached to this application are 1) the modeling protocol, 2) supplemental information to the BACT analysis, 3) performance data and emissions calculations, 4) modeling files on a CD, 5) a threatened and endangered species analysis for the power generation site, 6) a historical preservation act analysis for the site, and 7) a description of alternative conbustion technologies.

1.4 Applicant Information

Listed below are the applicant's primary points of contact and the address and phone number where they can be reached. This PSD application has been prepared by a third party under the direction of Steag Power, LLC and a contact has been included for the permitting consultant as well.

Applicant’s address

Corporate Office	Steag Power, LLC Three Riverway, Suite 1100 Houston, Texas 77056
Project Site	Central San Juan County, New Mexico Navajo Nation Territory

Applicant's Contact

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2.0 PROPOSED PROJECT

Steag is proposing develop a mine-mouth coal-fired power plant. The power plant will be erected in the Northwestern Area of New Mexico at an operating mine, of BHP Billiton New Mexico Coal, one of the largest domestic suppliers of low-sulfur coal. The power plant will be a supercritical pulverized coal type and is designed for a total nominal generation capacity of 1,500 MW (gross), composed of two units of 750 MW (gross) and 683 MW (net) each. Use of a once through, supercritical steam cycle and other design features will enable this plant of be one of the most efficient steam electric plants ever built in the United States with a net efficiency greater than 40% based on the lower heating value of the fuel. State-of-the-art emission controls will be used to minimize emissions of potential air pollutants. Water consumption will be minimized by using a Heller system, dry natural draft cooling tower. Solid wastes produced by the air pollution control system will be returned to the mine.

2.1 Project Location

The Desert Rock Energy Facility will be located on an ~580 acre site close to the BHP Navajo mine in Northwest New Mexico. The site location is ~25 miles Southwest of Farmington, San Juan County, New Mexico in the Navajo Indian Reservation as shown in Figure 2-1. The site can be accessed via Highway 249 from Shiprock, NM and further on Indian Service Routes to be improved for transportation purposes by grading, drainage and paving. No transportation is possible by railway.

Figure 2-1 General View – Farmington Region

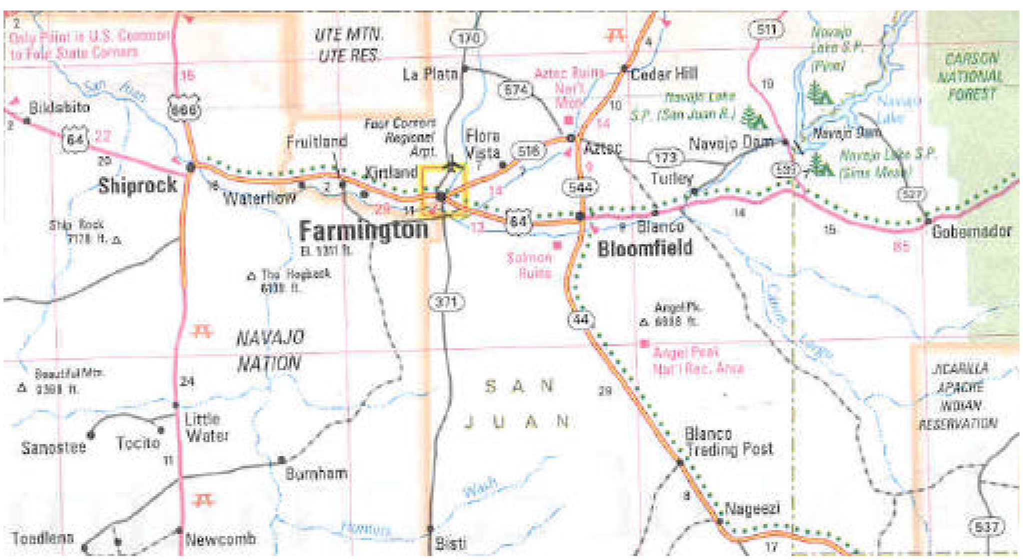


Figure 2-2 shows the location of the transmission line routes for the Project, as well as other power plants in the area. Figure 2-3 provides an impression of the project site. The project site can be characterized by open flat prairie. Chaco River is a slow creek with extended wetlands, which may fall dry during summer season.

2.2 Project Combustion Technology Selection

Four technologies may be considered for a new large coal fueled power plant as listed below:

- Pulverized Coal Combustion (sub-critical steam production)
- Pulverized Coal Combustion (supercritical steam production)
- Circulating Fluidized Bed (CFB) Combustion
- Integrated Gasification Combined Cycle (IGCC)

These four technologies are discussed further in Attachment 7. The choice of technology for a specific project is affected by many variables including, but not limited to, project location, the size of the project, fuel cost and source or sources, land or space availability, the developer's experience with a technology, electricity markets and many other factors. These variables affect the capital cost, operating cost, technological risks, and environmental impacts in different ways for each specific project. Key factors that affected the decision to select a pulverized coal-fired supercritical boiler for the Desert Rock Energy Facility are highlighted in this section.

Steag is proposing a green-field stand alone 1,500 MW gross power plant at a mine mouth site in New Mexico. Two large, high efficiency, supercritical pulverized coal-fired boilers can be installed to generate 1,500 MW. Economies of scale are favorable for these large units and the fuel to electricity efficiency of about 40% is very high. The plant will have a single source of fuel, the adjacent mine, so fuel flexibility is not important. Air pollutant emissions can be controlled to very low levels using state-of-the-art emission controls. Solid wastes generated by the air pollution control system can be returned to the mine.

Sub-critical pulverized coal-fired boilers would be similar to the planned supercritical pulverized coal-fired boilers except that the fuel to electricity efficiency would be significantly lower. At a typical efficiency of 35% a sub-critical pulverized coal-fired boiler would burn 15% more fuel than a supercritical boiler to produce the same amount of electricity. Steag's evaluation favored a supercritical boiler, in part, due to the high efficiency and lower emission associated with burning less fuel. Therefore, the option to install a sub-critical boiler was rejected.

Figure 2-2 Location of the Desert Rock Energy Facility in Relation to Other Generating Stations in the Area

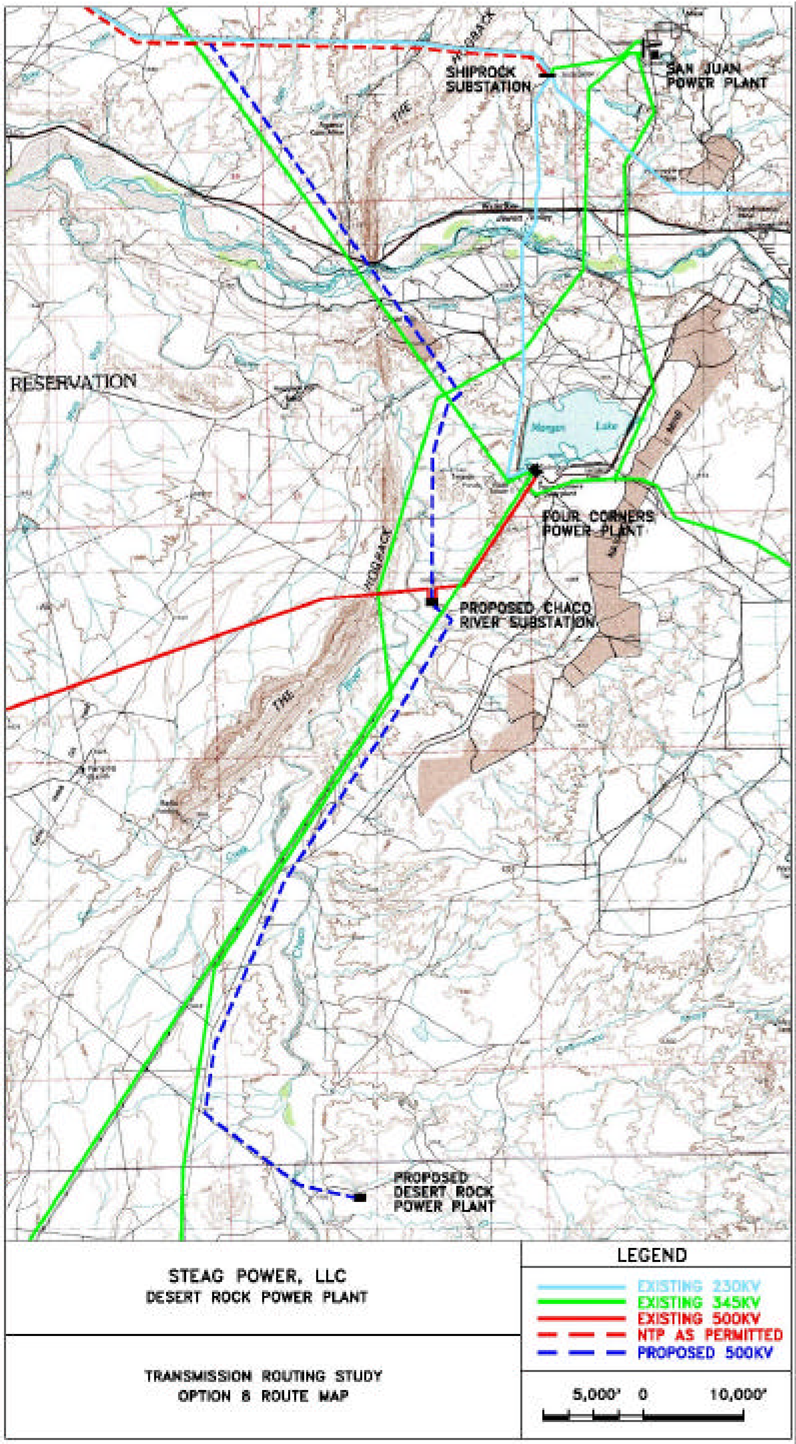


Figure 2-3 Local Terrain in the Power Plant Site Area

CFBs are not currently operating in supercritical steam cycles so efficiencies are similar to sub-critical pulverized coal-fired boilers. Although a possible advantage of a CFB is fuel flexibility, this is not a factor for the planned mine mouth power project. Limitations on the size of a CFB boiler would require 4 to 6 CFB boilers instead of the planned 2 PC boilers. For the planned project, two supercritical PC boilers are favored over the CFB option.

IGCC is a developing technology that may offer high thermal efficiencies. The three projects built to date in the U.S. have been demonstration projects partially funded by the Department of Energy. No coal based IGCC plants have been built in the U.S. without government funding. IGCC is a very complex and capital intensive technology that, to date, has been subject to availability problems. Although IGCC is cost competitive in many worldwide locations when using petroleum residual feed stocks, it is not economically competitive when using coal. IGCC is not a pollution free technology. Instead, emissions from an IGCC plant are well controlled by a complex and expensive array of gas cleaning systems required to clean the syngas in order to protect the gas turbine. IGCC is not currently an available or commercially viable technology for a 1,500 MW commercial coal-fired power plant. Therefore, the IGCC option was rejected for the planned project.

Table 2-1 presents a comparison of the performance data for the four coal combustion technologies identified above. Pulverized Coal combustion and IGCC have virtually no inherent emission control and must rely solely on back end add-on pollution control equipment. Circulating fluidized beds are inherently lower emitting combustion processes, and this technology actually prevents SO_2 and NO_x from being emitted from the process in the first place. The control of SO_2 for CFB includes adsorbent injection, which is also necessary to burn the coal in suspension – it is therefore inherent to the process itself. Similarly, staged combustion, low temperature combustion and ammonia injection directly into the solids separation stage of the CFB prevents NO_x from being emitted prior to the air pollution control train, and is also inherent to the technology. In order to permit a new coal-fired generation facility using any coal combustion technology will require best available emission control levels that are as low or lower than the current state-of-the-art – hence, “Clean Coal Technology”.

Table 2-1
Range of Emissions Control from Coal Combustion Technologies

Coal Technology	Efficiency (%)	%NO_x Controlled	%SO_2 Removed
Sub-critical PC	34 to 37	90% (add-on)	92-96% (add-on)
Supercritical PC	39 to 45	90% (add-on)	92-96% (add-on)
CFB [1]	34 to 37	50 to 80%	75 to 92%
IGCC	38 to 45 [2]	70 to 90%	90 to 99.9%

1. Dependent on sorbent activity and injection rate.
2. Current operating plants do not achieve 45% efficiency.

Source: World Bank.

2.3 Project Diagrams

A plot plan for the facility is shown in Figure 2-4, a side view is shown in Figure 2-5, and a process flow diagram is shown in Figure 2-6.

2.4 Process Equipment Description

This section describes the major equipment and components of the Project.

2.4.1 Coal Handling

Low sulfur coal from the BHP Billiton New Mexico Coal mine will be delivered to the project site by conveyor. A passive or inactive coal pile will be built on the site for emergency purposes. Normal preparation, blending (if necessary), and storage will be handled by the mine on their property. The conveyor from the BHP Billiton mine will move coal through a series of transfer houses where the coal will drop onto conveyors for transport to bunkers provided for each boiler. From the bunkers, coal is fed through pulverizers to the boilers.

Figure 2-4 Facility Side View of a Boiler Unit at the Proposed Desert Rock Energy Facility

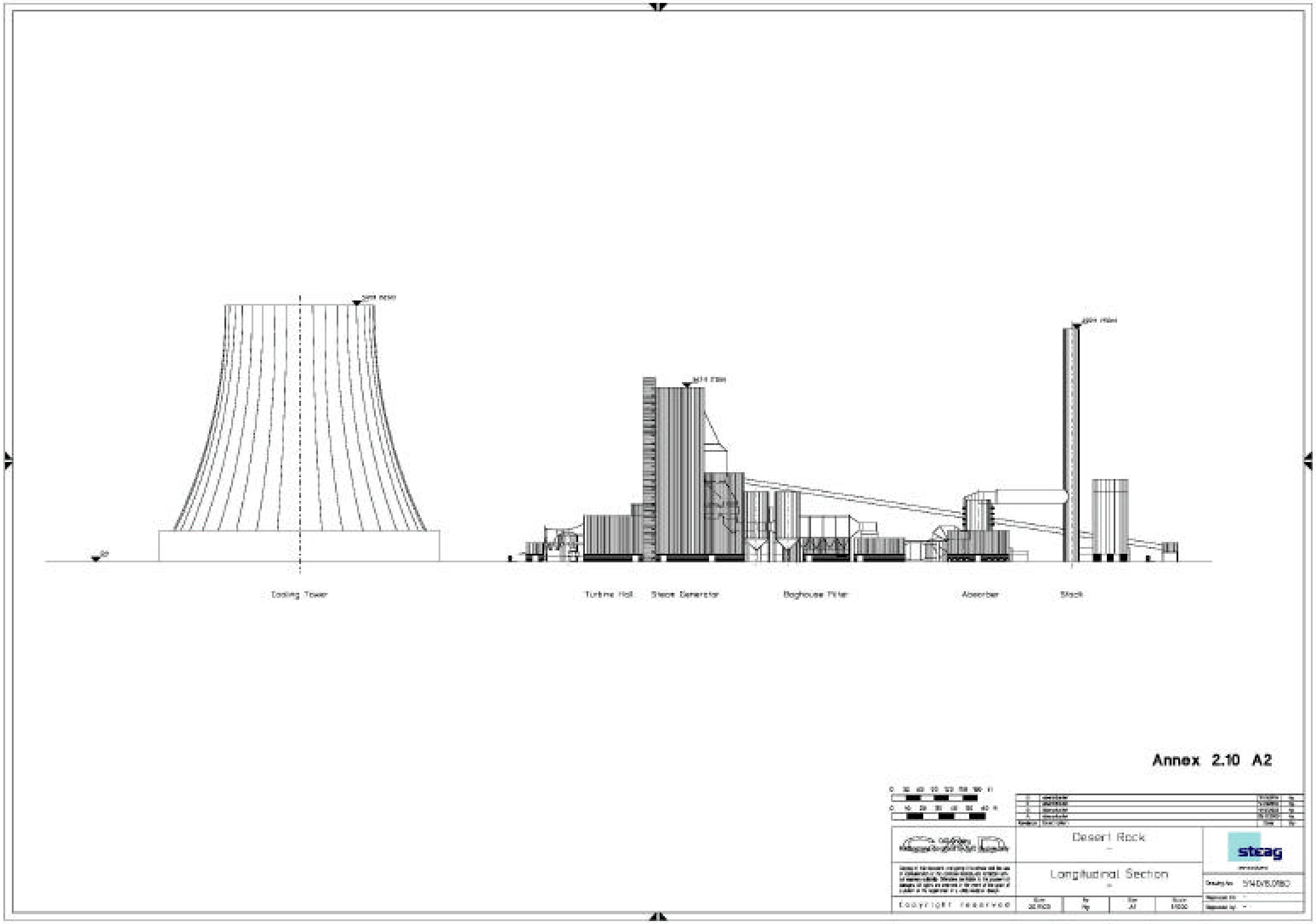


Figure 2-5 Detailed Plot Plan of Boiler Units

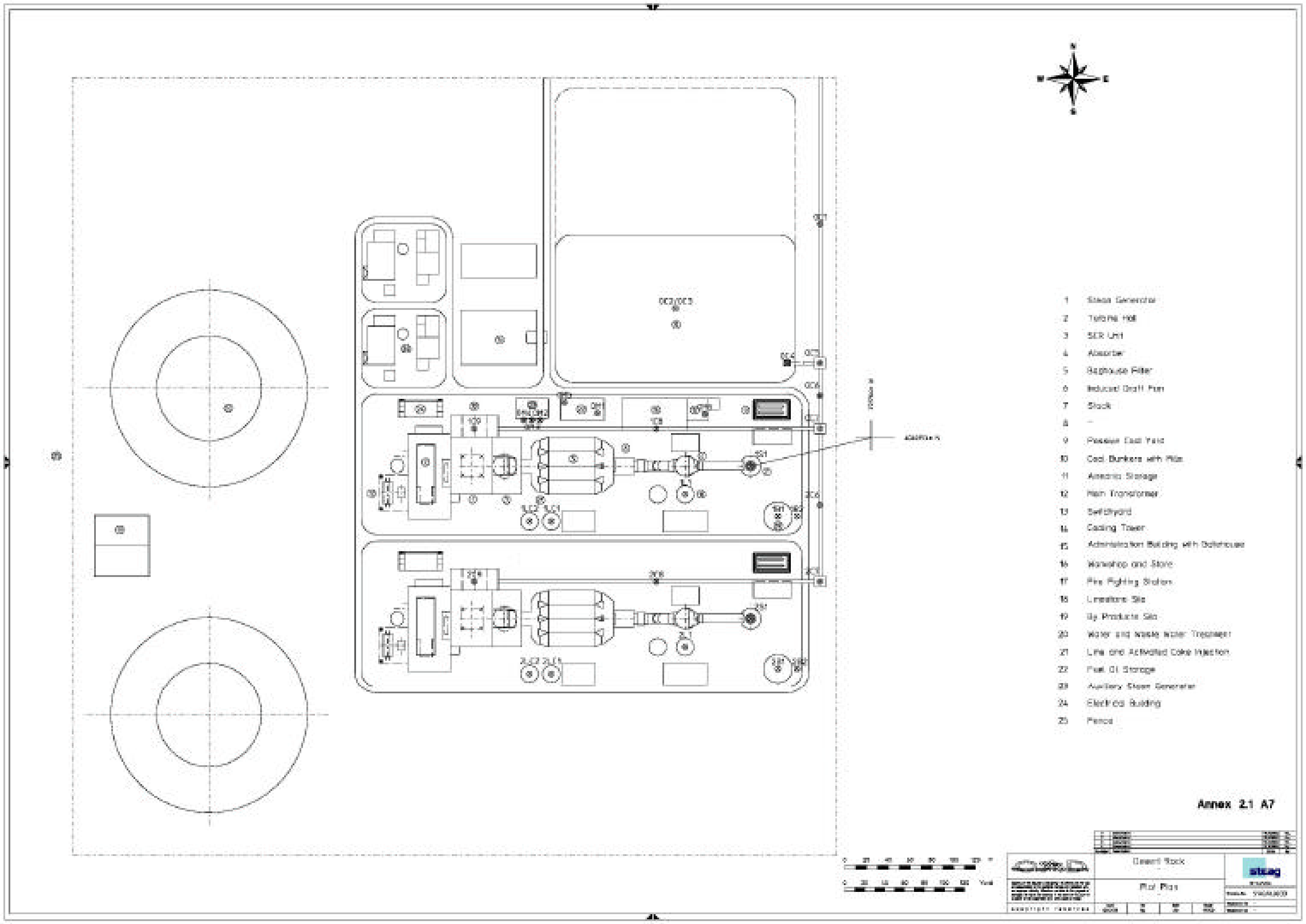
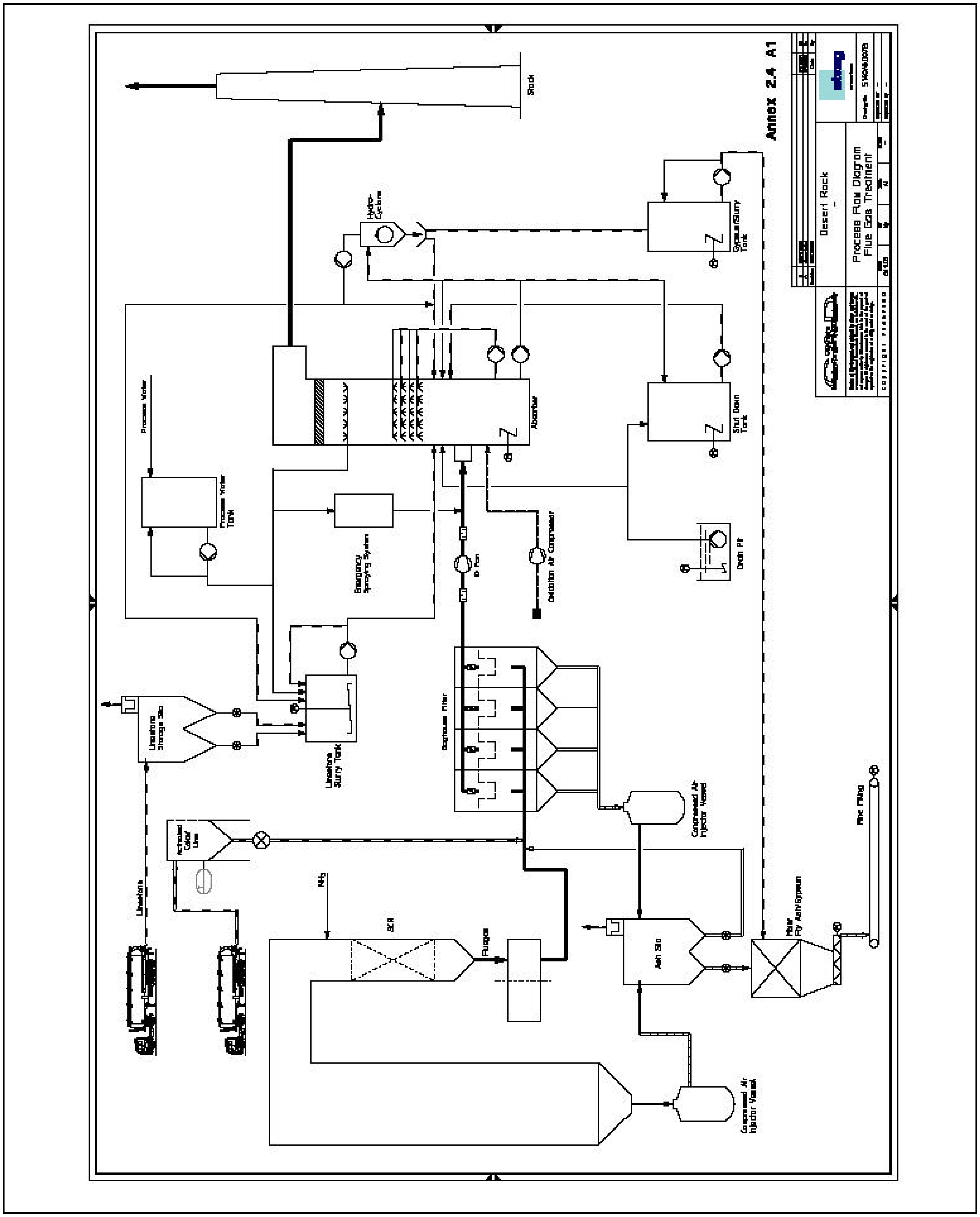


Figure 2-6 Process Flow Diagram



This on-site coal pile will be covered and sealed to prevent emissions and spontaneous combustion. Conveyors are totally enclosed to prevent emissions. Dust suppression, enclosures, or baghouses will be used, as appropriate, to control emissions from material transfer points and the coal bunkers.

Coal specifications are presented in Table 2-2.

Table 2-2
Fuel Data for Main Boilers

	Units	Design Fuel	Fuel Range
1. Fuel quality (Coal) Proximate analysis			
Higher heating value (HHV)	Btu/lb (kJ/kg)	8,910 (20,725)	8,550 - 9,380 (19,887 - 21,818)
Lower heating value (LHV) or net calorific value	Btu/lb (kJ/kg)	8,479 (19,723)	
Total moisture	%	14.2	13.4 – 15.6
Ash content	%	20.5	17.6 – 23.4
Sulfur	%	0.82	< 1.2
Volatile matter	%	31.7	27.6 – 36
Coal particle size	In	0-2	0-2
Percentage of outsize particle size	%	10	10
Max. coal particle size	In	4	4
2. Ultimate analysis			
Carbon	% wt.	56.38	41.96 – 70.26
Hydrogen	% wt.	2.99	1.81 – 4.29
Oxygen (balance)	% wt.	6.8	2.36 – 15.42
Nitrogen	% wt.	1.00	0.56 – 1.47
Sulfur	% wt.	0.82	0.59 – 0.98
Chlorine	% wt.	0.01	= 0.03
Fluorine	% wt.	0.01	= 0.05
Mercury	ppm	0.046	0.2

2.4.2 Pulverized Coal-fired Boilers

The power plant will be of the supercritical pulverized coal type and is designed for a total nominal generation capacity of 1,500 MW (gross) divided into two units of 750 MW (gross) and 693 MW (net) each. Each boiler will have a heat input of capacity of approximately 6,800 MMBtu/hr (extreme maximum) and will burn up to 382 tons/hour of coal. In the supercritical cycle, steam is produced at

3,626 psi and 1,112 °F at a rate of 4,636,000 lb/hour. The high-pressure steam is fed through a steam turbine generator to generate electricity and then to a direct contact jet condenser.

Air pollution controls for the pulverized coal-fired boilers will consist of the following:

- Low NO_x burners and selective catalytic reduction (SCR) to control NO_x emissions;
- Low sulfur coal, hydrated lime injection before a fabric filter, and wet limestone flue gas desulfurization to control SO_2 emissions;
- Hydrated lime injection before a fabric filter, and wet limestone flue gas desulfurization to control acid gas emissions including sulfuric acid mist;
- Activated carbon injection (if needed), hydrated lime injection before a fabric filter, and wet limestone flue gas desulfuriation to control mercury emissions;
- A fabric filter to control particulate emissions; and
- Good combustion to control CO and VOC emissions.

2.4.3 Cooling Towers

A direct contact jet condenser will be used with a Heller cooling tower system. In this cooling system, the process steam from the steam turbine is fed to the condenser and condensed by direct cooling with the cooling water coming from the cooling cycle. The blended cooling water and condensate are collected in the hot-well and extracted by circulating water pumps. Approximately 2% of this flow – corresponding to the steam condensed – is fed to the boiler feed water system by condensate pumps. The major part of the flow is returned to the cooling tower for recooling. The cooling duty is performed by the cooling deltas, divided into parallel sectors, where cooling air flow is induced by a natural draft cooling tower.

The Heller-type hybrid cooling tower is used to minimize water consumption. When the ambient temperature is below 80 °F, the cooling tower operates like a natural draft cooling tower. When the temperature exceeds 80 °F, water oversprays are injected on the heating surfaces inside of the cooling tower to provide additional cooling. This type of cooling tower has no particulate emissions.

2.4.4 Auxiliary Boilers

Three auxiliary steam generators provide auxiliary steam demand during stand still and start up of the main steam generator (auxiliary steam consumers: dearator, atomizing steam for oil firing not a mechanical atomizer in use, steam air heater, turbine seals etc). The auxiliary steam generators are of fire-tube/smoke-tube type (package boilers, shell type). Each auxiliary steam generator has a heat input capacity of 86.4 MMBtu/hour. Emission are controlled by only burning low sulfur (0.05% sulfur) distillate oil, low NO_x burners, good combustion, and limiting operation to an average of 2,000 hour/year per boiler.

2.4.5 Emergency Diesel Generators and Firewater Pumps

There will be two emergency diesel generators with capacities of 1,000 kW and two firewater pumps with capacities of 180 kW. Emission will be controlled by only burning low sulfur (0.05% sulfur) distillate oil, ignition timing retard with turbocharging and aftercooling, good combustion, and limiting operation to an average of 500 hour/year per engine.

2.4.6 Fuel Oil Supply

Low sulfur distillate oil (0.05% sulfur) will be used for startup of the pulverized coal-fired boilers and operation of three auxiliary boilers. Oil will be delivered to the site by truck, unloaded at one of two unloading stations and stored in a 1.1 million gallon tank.

2.4.7 Limestone Supply

Ground limestone is delivered to the site by trucks and pneumatically conveyed to a limestone storage silo. The silo will be equipped with a baghouse to control PM_{10} emissions. Limestone will be withdrawn from the bottom of the silo by a rotary vane feeder and transported to the limestone slurry tank where it is mixed with water. The limestone slurry will be used in the wet flue gas desulfurization system.

2.4.8 Hydrated Lime and Activated Carbon Supply

Hydrated lime and activated carbon, if needed, will be delivered to the site by trucks and pneumatically conveyed to storage silos. The silos will be equipped with a baghouse to control PM_{10} emissions. Hydrated lime will be injected in the duct prior to the fabric filter to control acid gas emissions. Activated carbon will be injected, if necessary, in the duct prior to the fabric filter to control mercury emissions.

2.4.9 Anhydrous Ammonia Supply

Anhydrous ammonia will be delivered to the site by truck for storage in a pressurized tank. There are no air pollutant emissions from the pressurized storage tanks. The anhydrous ammonia system consists of all equipment required to unload, compress, store, transfer, vaporize, dilute, and convey the ammonia/air mixture into the ammonia injection grid upstream of the selective catalytic reduction system.

2.4.10 Ash Handling

Fly ash will be collected by the main fabric filter. The pulverized coal-fired boiler will generate bottom ash. Fly ash and bottom ash will be mixed in an ash silo. Emissions from the ash silo will be controlled by a fabric filter. Gyspum, with a water content in the 10% to 20% range, will be generated by the wet flue gas desulfurization system. The gypsum and mixed ash will be mixed together and then transported by to the mine by a conveyor.

3.0 REGULATORY SETTING

This project will be built on land leased from the Navajo Nation. As a federally recognized tribe, the Navajo Reservation is considered sovereign land and is not subject to the regulations of the State of New Mexico. They are subject to the U.S. Environmental Protection Agency (EPA) regulations as are individual States. This project will be under the jurisdiction of EPA Region IX, since the majority of the Navajo Nation is located in Arizona. All local regulations will be administered by the Navajo Nation EPA (NN EPA) which have been adopted for the most part from the New Mexico Environmental Department (NMED) regulations. The Navajo Nation has not been delegated authority under the Clean Air Act to issue a Prevention of Significant Deterioration permit by EPA, so the PSD permit will be issued by EPA Region IX.

This section presents a review of the air quality regulatory requirements applicable to the construction and operation of the Desert Rock Energy Facility.

3.1 Ambient Air Quality Standards and Current Attainment Status

National Ambient Air Quality Standards (NAAQS) are established for specific air pollutants based on health effects criteria. The NAAQS for these *criteria* pollutants are expressed as total concentrations of the pollutants in the air to which the general public is exposed. The NAAQS are presented in Table 3-1. The facility will be located near Farmington, San Juan County, New Mexico. This area is part of New Mexico Air Quality Control Region (AQCR) 014. The current air quality of the AQCR, based on actual measurement data, is better than the NAAQS. Thus AQCR 014 is designated as attaining the NAAQS for all criteria pollutants.

Similar to the NAAQS, New Mexico has state ambient air quality standards (NMAAQS). The NMAAQS are defined in section 20.2.3 NMAC of the New Mexico Air Quality Regulations and are listed in Table 3-2. The current air quality of the AQCR is also better than the NMAAQS.

The Project will be required to demonstrate that it will neither cause nor contribute to a violation of either the NAAQS or the NMAAQS. The NMAAQS apply only in the area in New Mexico located outside the Navajo Nation.

Major new sources located in attainment areas are required to obtain a PSD permit prior to initiation of construction.

Table 3-1
Ambient Air Quality Standards

Pollutant	Averaging Period[2]	National AAQS[1]	
		Primary	Secondary
SO_2	Annual	80	--[3]
	24-hour	365	--[3]
	3-hour	--[3]	1300
PM_{10}	Annual	50	50
	24-hour	150	150
$PM_{2.5}$	Annual	15	15
	24-hour	65	65
CO	8-hour	10,000	--[3]
	1-hour	40,000	--[3]
Ozone	1-hour	235	235
	8-hour	157	157
NO_2	Annual	100	100
Lead	3-month	1.5	--[3]

1. All standards in this table are expressed in $\mu g/m^3$.

2. National short-term ambient standards may be exceeded once per year; annual standards may never be exceeded. Ozone standard is attained when the expected number of days of an exceedance is equal to or less than one.

3. No ambient standard for this pollutant and/or averaging period.

Source: 40 CFR 52.21

Table 3-2
New Mexico Ambient Air Quality Standards

Pollutant	Averaging Period	Air Quality Standard (ppm)
NO_2	Annual[1]	0.050
	24-hour	0.01
SO_2	Annual[1]	0.02
	24-hour	0.10
TSP	Annual[2]	60[3]
	30-day	90[3]
	7-day	110[3]
	24-hour	150[3]
CO	8-hour	8.7
	1-hour	13.1
H_2S	1-hour	0.010[4]

1. Arithmetic Mea
2. Geometric mean
3. µg/m^3
4. For the entire State with the exception of Pecos-Permian Basin Intrastate AQCR, no to be exceeded more than once per year.

Source: 20.2.3 NMAC

3.2 Prevention of Significant Deterioration (PSD) Requirements

PSD review applies to specific pollutants for which a project is considered major and the project area is designated as attainment or unclassified with respect to the NAAQS. For a new facility to be subject to PSD review, the project's potential to emit (PTE) must exceed the PSD major source thresholds, which are:

- 100 tpy if the source is one of the 28 named source categories, or
- 250 tpy for all other sources

The Project is one of the 28 named categories, specifically a fossil fuel fired steam-generating plant with heat input greater than 250 MMBtu/hour. As such, the applicable PSD threshold is 100 tpy. Once it is determined that a pollutant exceeds the PSD major source threshold, additional pollutants will be subject to PSD review if their potential to emit (PTE) exceeds the PSD Significant Emission Rates. Table 3-3 compares the Project annual PTE with the PSD significant emission rates. As shown in the table, the Project's PTE is estimated to be greater than the PSD significant emission rates for these PSD pollutants. PSD review and approval will therefore be required for these pollutants.

Table 3-3
Comparison of Project Annual PTE to the PSD Thresholds

Pollutant	PSD Significant Emission Rate (tpy)	Project PTE [1] (tpy)
CO	100	5,967
NO_x	40	4,209
SO_2	40	3,588
Particulate Matter (TSP/PM)	25	732
PM_{10}	15	1,208
Ozone (VOC)	40	180
Lead	0.6	11.9
Beryllium	0.004	0.062
Fluorides	3	14.3
Sulfuric Acid Mist (H_2SO_4)	7	292
1. Assumes 100 percent availability at full load emissions.		

3.2.1 Best Available Control Technology

A PSD source must conduct an analysis to ensure the application of the Best Available Control Technology (BACT) to emissions of pollutants subject to PSD review. Guidelines for the evaluation of BACT can be found in EPA's Cost Control Manual (USEPA 1996, 2002) and in the PSD/NSR Workshop Manual (EPA 1990 DRAFT). These guidelines were drafted by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters.

3.2.2 Air Quality Monitoring Requirements

In accordance with requirements of 40 CFR 52.21(m), any application for a PSD permit must contain an analysis of existing ambient air quality data in the area to be affected by the proposed project. The definition of existing air quality can be satisfied by air measurement data from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source. This condition may be waived if a project would cause an impact less than EPA-specified *de minimis* monitoring levels established by the EPA. The de minimis monitoring levels are listed in Table 3-4.

Table 3-4
PSD *De Minimus* Monitoring Concentrations

Pollutant	Avg. Period	Threshold Concentration ($\mu g/m^3$)
CO	8-hour	575
NO_2	Annual	14
SO2	24-hour	13
PM/PM_{10}	24-hour	10
O_3	NA	-[1]
Lead	3-month	0.1
Fluorides	24-hour	0.25
Total Reduced Sulfur	1-hour	10
Reduced Sulfur Compounds	1-hour	10
Hydrogen Sulfide	1-hour	0.2
1. Exempt if VOC emissions are less than 100 tpy		

3.2.3 Air Quality Impact Analysis

An air quality impact analysis (AQIA) must be performed for a proposed project subject to PSD review for each pollutant for which the increase in emissions exceeds the de minimis emissions rate. The PSD regulations specifically provide for the use of atmospheric dispersion modeling in performing the AQIA. Guidance for the use and application of dispersion models is presented in the EPA publication

Guideline on Air Quality Models (USEPA 1999). The impact analysis may be limited to only the new source if impacts are below significant impact levels (SILs).

The AQIA is governed by a modeling protocol designed for the specific source type and surrounding dispersion regime. The modeling protocol implemented for this application is included as an appendix to this report.

The cumulative incremental air quality impacts to baseline air quality from all PSD sources significantly impacting an area are limited to the PSD increments listed in Table 3-5. In no case, however, can the incremental impacts cause a violation of the NAAQS. PSD Increments are established for PM_{10}, SO_2, and NO_2 for two types of areas, Class I and Class II. Class I areas are those in which the least amount of incremental impact can occur. Class I areas are federally mandated and include specific National Parks, National Forests and Wilderness Areas.

Table 3-5
Allowable PSD Increments and Significant Impact Levels (μg/m^3)

Pollutant	Averaging Time	PSD Increments		Significant Impact Levels
		Class I	Class II	Class II
PM_{10}	Annual Arithmetic Mean	4	17	1
	24-hour Maximum	8	30	5
SO_2	Annual Arithmetic Mean	2	20	1
	24-hour Maximum	5	91	5
	3-hour Maximum	25	512	25
CO	8-hour Maximum	NA	NA	500
	1-hour Maximum	NA	NA	2,000
NO_2	Annual Arithmetic Mean	2.5	25	1

NA = Not applicable, i.e., no standard exists for this pollutant or averaging period
Source: 40CFR50; 40CFR52.21, 40CFR51.165

3.2.4 Additional Impacts Analyses

The additional impact analysis consists of three elements:

1. Growth
2. Soils and Vegetation Impacts
3. Visibility Impairment

The growth analysis projects air pollutant emissions associated with industrial, commercial, and residential growth in direct support of the new source. Residential growth includes housing for employees entering the region while industrial and commercial growth includes new sources providing goods and services to the new employees and to the proposed source.

The analysis of impacts on soils and vegetation in the source's impact area compares the total air quality impacts to concentrations known to cause harmful effects to the resident species. The visibility impairment analysis addresses impacts that occur within the impact area of the proposed new source, beginning with an initial screening for possible impairment and, if warranted, a more in-depth analysis with computer modeling. The local visibility impairment analysis is distinct from the visibility impairment analysis required for PSD Class I areas, discussed below.

3.2.5 PSD Class I Area Analysis

In addition to the analysis of PSD Class I Increment compliance, the PSD Class I analysis must also address impacts to special attributes of a Class I area that deterioration of air quality may adversely affect. Such attributes are referred to as Air Quality Related Values and are specified by the Federal Land Manager (FLM) of the respective Class I area. These analyses generally include visibility impacts, such as plume blight or contribution to region haze, and impacts from acid deposition.

3.3 Good Engineering Practice Stack Height Analysis

EPA regulations require the degree of emission limitation required for control of any pollutant not to be affected by a stack that exceeds the Good Engineering Practice (GEP) height. GEP height is reflective of the height necessary to avoid having the exhaust caught in the downward flow of air currents created by structural and or ground effects, referred to as downwash. The portion of a stack, if any, that exceeds GEP height as defined by EPA cannot be used in atmospheric modeling of the source's impacts. Conversely, the dispersion modeling of emissions from stacks below GEP height must reflect the downwashing effects.

3.4 New Source Performance Standards

New Source Performance Standards (NSPS) apply to all sources within a given source category, regardless of geographic location or NAAQS attainment status. The standards define emission limitations that would be applicable to a particular source group. For PSD sources, BACT can be no less stringent than any applicable NSPS. The NSPS (contained in 40 CFR 60) applicable to the project will include:

- Subpart A – General Provisions
- Subpart Da – Electric Utility Steam Generating Units
- Subpart Dc – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

- Subpart Y - Coal Preparation Plant

3.5 National Emissions Standards for Hazardous Air Pollutants

National Emissions Standards for Hazardous Air Pollutants (NESHAPS) are reflected in a requirement for Maximum Achievable Control Technology (MACT) standards, determined by EPA through an analysis of the best controlled sources in a category and the cost of more stringent available controls. A new source emitting more than 10 tons per year of a single Hazardous Air Pollutant (HAP) or 25 tons per year of a combination of HAPs is defined as a major source and must secure MACT approval prior to construction. If a MACT standard has not yet been promulgated for the source category, the applicant must secure case-by-case MACT approval.

A MACT standard for the oil- and coal-fired electric utility steam generating unit source category has not yet been promulgated. Since the project is expected to be a major source of HAP, a case-by-case MACT approval will be required.

3.6 Title V – Major Source Operating Permit

Currently, the Navajo Nation has not been delegated authority for the Title V program. Until such authority is granted, a Title V permit under 40 CFR Part 71, administered by EPA, would be needed.

The Desert Rock Energy Facility will be required to submit a Title V operating permit application to EPA (or the Navajo Nation if they received Title V delegation prior to the facility's one-year operation anniversary date) no later than 12 months after the commencement of operation. The application and permit will essentially incorporate the requirement for operation encompassed by the PSD permit.

3.7 Compliance Assurance Monitoring

On October 27, 1997, EPA promulgated the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, which addresses monitoring for certain emission units at major sources, thereby assuring that facility owners and operators conduct effective monitoring of their air pollution control equipment. In order to be subject to CAM, the following criteria must be met:

- The unit is subject to an emissions limitation or standard for the pollutant of concern;
- An "active" control device is used to achieve compliance with the emission limit; and
- The emission unit's pre-control potential-to-emit is greater than the applicable major source threshold.

The CAM rule does not apply to emissions units/pollutants that are subject to Sections 111 (NSPS) or 112 (NESHAP) of the CAA issued after November 15, 1990; the Acid Rain program or emissions trading programs. Most emissions units/pollutants at the proposed project would be covered by other monitoring requirements. Monitoring plans for any emissions units/pollutants subject to CAM would be required to be developed with the submittal of the facility's Title V permit application.

3.8 Acid Rain Provisions

The proposed coal-fired boilers for the Desert Rock Energy Facility are subject to the Acid Rain Program (ARP) pursuant to Title IV of the CAA Amendments of 1990. This will require:

- An Acid Rain Permit
- Continuous Emissions Monitoring System conforming to the ARP requirements.
- Allowances equivalent to annual SO_2 emissions; and
- Emission limits of 40 CFR 76, to which BACT limits will conform or exceed.

The Acid Rain permit application must include the date that the unit will commence commercial operation and the deadline for monitoring certification (90 days after commencement of commercial operation). A Title IV Acid Rain monitoring plan will be submitted as required under 40 CFR 72. The plan will include the installation, proper operation and maintenance of continuous monitoring systems or approved monitoring provisions under 40 CFR 75 for NO_X, SO_2, CO_2, and opacity. Depending on the monitoring technology available at the time of installation, the plan will cite the specific operating practices and maintenance programs that will be applied to the instruments. The plan also will cite the specific form of records that will be maintained, their availability for inspection, and the length of time that they will be archived. The plan will cite that the Acid Rain permit and applicable regulations will be reviewed at specific intervals for continued compliance and the specific mechanism that will be used to keep current on rule applicability.

3.9 Risk Management Program

The project will utilize anhydrous ammonia in the selective catalytic reduction system to control NOx emissions from the boilers. The storage amount of anhydrous ammonia will require a Risk management Plan in accordance with EPA rules. Three elements comprise the RMP:

- Hazard Assessment;
- Prevention Program; and
- Emergency Response Program.

An approved RMP must be in place prior to exceeding the threshold storage amount of anhydrous ammonia (10,000 lbs).

4.0 CONTROL TECHNOLOGY EVALUATION

4.1 Control Technology Overview

Steag's proposed new 1,500 MW plant (the Project) is subject to Best Available Control Technology (BACT) for oxides of nitrogen (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), particulate matter smaller than 10 micrometer diameter (PM_{10}), Volatile Organic Compounds (VOCs), lead (Pb), beryllium (Be), hydrogen fluoride (HF), and sulfuric acid mist (H_2SO_4). Mercury (Hg) and hydrogen chloride (HCl) have been targeted for future regulation under the Maximum Available Control Technology (MACT) standards for coal-fired power plants. This document presents a "Top Down" BACT analysis, which begins with identification of the most stringent level of control achieved on similar units. This level of control is referred to as the Lowest Achievable Emission Rate (LAER). BACT is presumed to be equivalent to LAER unless case-specific technical feasibility, economic or environmental impacts would preclude it's practical application to the proposed project. If such factors are identified, the next best level of control is similarly evaluated, and this process continues until the BACT level is determined on a case-by-case basis for the particular emission units being evaluated for control.

A case-by-case MACT analysis is also presented.

4.1.1 Lowest Achievable Emission Rate

LAER is the most stringent control requirement for a source and is used as the starting point of a top down BACT analysis. LAER, as defined in the "New Source Review Workshop Manual" (U.S. EPA, October 1990), is derived from either of the following definitions:

> *"The most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or the most stringent emission limitation achieved in practice by such class or category of source."*

LAER would be automatically required for those criteria pollutants subject to non-attainment New Source Review if the project were located in a non-attainment area. The proposed project is located in an area that is designated attainment for all criteria pollutants, and is not subject to LAER. The LAER standard is more stringent than BACT, since it considers only technological applicability of the best level of control achievable, and not economic, environmental, or energy factors when determining emission limits. To determine the applicable emission limitations that would be representative of LAER, several sources were consulted including EPA's RACT/BACT/LAER Clearinghouse (RBLC) and recent permits issued for similar sources not yet listed in the EPA clearinghouse.

4.1.2 Top-Down BACT

BACT requirements are intended to ensure that a proposed facility will incorporate control systems that reflect the latest demonstrated practical techniques for a particular type of emission unit and do not result in the exceedance of a NAAQS, PSD increment, or other standard imposed at the state level. The BACT evaluation requires the documentation of performance levels achievable for each technically feasible pollutant control technology applicable to the Project.

EPA recommends that a "top-down" approach be taken when evaluating available air pollution control technologies. This approach to the BACT process involves determining the most stringent control technique available (LAER) for a similar or identical emission source. If it can be shown that the LAER is technically, environmentally, or economically impractical on a case-by-case basis for the particular source under evaluation, then the next most stringent level of control is determined and similarly evaluated. The process continues until a control technology and associated emission level is determined which cannot be eliminated by any technical, environmental, or economic objections. The top-down BACT evaluation process is described in the EPA draft document "New Source Review Workshop Manual. The five steps involved in a top-down BACT evaluation are:

- Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Eliminate technically infeasible technology options;
- Rank remaining control technologies by control effectiveness;
- Evaluate most effective control alternative and document results; if top option is not selected as BACT, evaluate next most effective control option; and
- Select BACT, which will be the most effective practical option not rejected based on energy, environmental, and economic impacts.

The "top-down" approach was used in this analysis to evaluate available pollution controls for the proposed Project.

4.1.3 Previous BACT/LAER Determination for Pulverized Coal-fired Boilers

EPA's RACT/BACT/LAER Clearinghouse (RBLC) is a listing of RACT, BACT, and LAER determinations by governmental agencies for many types of air emission sources. ENSR consulted this database as the first step in developing a list of the most recent BACT/LAER decisions for applicable source types including pulverized coal facilities. The results of the RACT/BACT/LAER Clearinghouse search and information from more recent permits are summarized on a pollutant specific basis in the following sections to identify and rank alternative technologies and achievable levels of control.

4.2 BACT for Nitrogen Oxides (NO_x)

4.2.1 Pulverized Coal-fired Boilers

4.2.1.1 Formation

NO_x is formed during the combustion of coal and is generally classified as either thermal NO_x or fuel NO_x. Thermal NO_x is formed when elemental nitrogen reacts with oxygen in the combustion air is introduced in the high temperature environment of the furnace. The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. Fuel NO_x is generated when nitrogen contained in the coal itself is oxidized. The rate of formation of fuel NO_x is a primarily a function of fuel bound nitrogen content of the coal but is also affected by fuel air mixing.

NO_x emissions can be reduced using either combustion controls (i.e., staged combustion techniques such as low NOx burners (LNB), flue gas recirculation (FGR), overfire air (OFA), or reburn, or flue gas treatment including selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR).

4.2.1.2 Ranking of Available Control Techniques

A review of EPA's RBLC and recent permit reviews indicates general levels of NO_x control that may be achieved with various combinations of control technology. Emission levels and control technologies for pulverized coal combustion have been identified and ranked as shown in Table 4-1.

Table 4-1
Ranking of NO_x Control Technologies for Pulverized Coal Boilers

Pulverized Coal Control Technologies	Typical Control Efficiency Range (% Removal)	Typical Emission Level[1] (lb/MMBtu)	Technically Feasible for Pulverized Coal Boilers
SCR	80-90	0.07-0.15 lb/MMBtu[2]	Yes
SNCR	40-60	0.2-0.3 lb/MMBtu[2]	Yes
Staged Combustion Techniques Including Low NO_x Burners	30-50	0.3-0.5 lb/MMBtu	Yes
SCONOx	N/A	N/A	No
Gas Reburn	40-60	0.2-0.3 lb/MMBtu	Requires Gas On Site

1. Emission levels represent target steady state values at base load.
2. Lower end of range is with Low NO_x burners.

N/A – Not available (no known installations of this technology on coal-fired boilers)

4.2.1.3 Recent Permit Levels

The four most recent PSD permits identified for new pulverized coal-fired units are Sand Sage Power, LLC in Kansas issued 10/8/02, Thoroughbred Generating Co. LLC in Kentucky, issued 10/11/02, Roundup Power in Montana issued 07/21/03 and Longview Power, LLC in West Virginia draft issued 12/4/03. These projects were subject to top down BACT, and the emission limits contained in those BACT approvals are representative of the current state-of-the-art for new pulverized coal power plants.

The Thoroughbred project will employ SCR to achieve a NO_x emission limit of 0.08 lb/MMBtu on eastern coal. This value has been proposed and demonstrated in practice on similar units burning eastern coal. The permit for Sand Sage reflects less certainty that a Powder River Basin (western) coal-fired unit will be able to meet the same emission rate on a continuous long-term basis. The Sand Sage permit contains a goal of achieving 0.08 lb/MMBtu after three years of operation, with an interim limit of 0.12 lb/MMBtu. The permit contains a provision to adjust the 0.08 lb/MMBtu upward if it is shown that despite good faith efforts it can not be continuously achieved in practice. The Roundup Power permit requires low-NO_x burner, overfire air and SCR to limit NO_x emissions to 0.07 lb/MMBtu as a 24-hour average. The Longview permit requires low-NO_x burners and SCR to limit NO_x emissions to 0.08 lb/MMBtu as a 24-hour average.

Based on these four recent BACT determinations, ENSR concludes that SCR in the range of 0.07 – 0.12 lb. NO_x/MMBtu is representative of state-of-the-art emission control for new pulverized coal units. Alternative control technologies with potential for application to the proposed Project are reviewed below.

4.2.1.4 NO_x Control Technology Discussion

Selective Catalytic Reduction

SCR is a process that involves post-combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions (Cho, 1994):

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \quad \text{(Equation 5-1)}$$

$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O \quad \text{(Equation 5-2)}$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \quad \text{(Equation 5-3)}$$

$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O \quad \text{(Equation 5-4)}$$

$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O \quad \text{(Equation 5-5)}$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems. These include the SCR reactor and flues, ammonia injection system and ammonia storage and delivery system. The SCR reactor with necessary inlet and outlet fluework will be located downstream of the economizer and upstream of the air heater and the particulate control system.

From the economizer outlet, the flue gas will first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas will then flow through the catalyst bed and exit to the air heater.

Three types of catalyst bed configurations have been successfully applied to commercial sources: the moving bed reactor, the parallel flow reactor, and the fixed bed reactor. The fixed bed reactor is applicable to sources with little or no particulate present in the flue gas. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow and transport of the reactants to the active catalyst sites takes place through a combination of diffusion and convection.

The SCR system for a pulverized coal boiler typically utilizes a fixed bed catalyst in a vertical down-flow multi-stage reactor. The reactor will include a seal system to prevent gas from bypassing the catalyst bed. Access openings for catalyst loading/removal and periodic internal inspection will be provided. The reactor will contain multiple stages of catalyst with room for loading a future stage. For each stage, a sootblowing system will be provided. Each stage will be equipped with a platform with monorails and hoists to accommodate catalyst loading and unloading.

Reduction catalysts are divided into two groups: base metal (lower temperature, primarily vanadium, platinum or titanium) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NO_x ratio, and optimum oxygen concentration. A disadvantage common to base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Platinum group catalysts have the advantage of requiring lower ignition temperature, but have been shown to also have a lower maximum operating temperature. Operating above the maximum temperature results in oxidation of ammonia to either nitrogen oxides (thereby actually increasing NO_x emissions) or ammonium nitrate.

Optimum operating temperature for a vanadium-titanium catalyst system has been shown to be in the range of 550° to 800°F, which is significantly higher than for platinum catalyst systems. However, the vanadium-titanium catalyst systems begin to break down when continuously operating at temperatures above this range. Consequently, operating above the maximum temperature for the catalyst system again results in the oxidation of ammonia to either nitrogen oxides (increasing NO_x emissions) or ammonium nitrate.

Sulfur content of the fuel can be a concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide (from trace sulfur in gas and the mercaptans used as an odorant) to sulfur trioxide (SO_3), which combines with water to form sulfuric acid. At typical SCR operating temperatures, SO_3 and sulfuric acid react with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled and can lead to increased emissions of PM_{10}. Further, sulfates and nitrates emitted from the stack are precursors to atmospheric formation of PM_{10}. Fouling may eventually lead to increased system pressure drop over time and decreased heat transfer efficiencies.

The SCR process is also subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically only guarantee a limited lifetime to very low emission level, high performance catalyst systems.

SCR manufacturers typically estimate 10 ppmvd of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which conversely results in ammonia slip. Thus an emissions trade-off between NO_x and ammonia may occur in high NO_x reduction applications.

The potential environmental impacts associated with the use of SCR are summarized below:

- Unreacted ammonia would be emitted to the atmosphere (ammonia slip).
- Ammonium salts would be emitted to the atmosphere as PM_{10} (and $PM_{2.5}$).
- Safety issues are associated with the transportation, handling, and storage of ammonia (aqueous or anhydrous).

Selective Non-Catalytic Reduction

SNCR has been applied to a number of different types of combustion sources, including petroleum heaters, utility and industrial boilers fired with natural gas and oil, as well as PC boilers and to coal-fired Circulating Fluidized Bed (CFB) boilers.

The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between NO_x in the flue gas and either injected NH_3 or urea to produce gaseous nitrogen and water vapor. SNCR systems do not employ a catalyst; the NO_x reduction reactions are driven by the thermal decomposition of ammonia and the subsequent reduction of NO_x. Consequently, the SNCR process operates at higher temperatures than the SCR process.

Critical to the successful reduction of NO_x with SNCR is the temperature of the flue gas at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1,700 - 1,900°F; for the urea injection process the nominal temperature range is 1,600 - 2,100°F. Also critical to effective application of these processes are gas mixing, residence time at temperature, and ammonia slip.

Theoretically, one mole of ammonia (or one-half mole of urea) will react with one mole of NO_x, forming elemental nitrogen and water. In reality, not all the injected reagent will react due to imperfect mixing, uneven temperature distribution, and insufficient residence time. These physical limitations may be compensated for by injecting a large amount of excess reagent and essentially achieving low NO_x emissions at the expense of emissions of unreacted reagent, referred to as ammonia "slip." These emissions represent an adverse environmental impact and can lead to formation of ammonium salts and may contribute to regional haze as a precursor to $PM_{2.5}$. Thus, for a given boiler configuration, there is a limit on the degree of NO_x reduction which can be achieved with SNCR while maintaining acceptable levels of ammonia slip.

A number of CFB boilers have been equipped with SNCR for NO_x control according to the listings in the RACT/BACT/LAER Clearinghouse. The CFB design is described as the ideal application for SNCR in the available open literature. CFB boilers are constant temperature, variable heat transfer devices. The bed temperature and downstream flue gas temperature can be set by the operator to within a few degrees. The typical temperature of CFB flue gas leaving the bed and entering the hot cyclone is at the ideal temperature for SNCR. Additionally, the reduction reagent is injected at the inlet to the hot cyclone, where all of the flue gas is swirled at 50-75 ft/second, and forced to change direction many times. This cyclonic action homogenizes the reagent flue gas NO_x concentration, thus maximizing mixing. SNCR has been applied to PC boilers more often as to achieve 30 – 50% reductions in response to Reasonably Available Control Technology (RACT) since the technology can be retrofit more readily than add-on control. Due to mixing limitations and a brief temperature window in which to react, SNCR is less effective at controlling NO_x from PC's compared with CFB's.

Staged Combustion

A number of techniques have been employed to reduce the formation of NO_x by reducing peak flame temperature and/or starving the hottest parts of the flame for oxygen. By staging the combustion process, a longer, cooler flame results, which forms less NO_x. Staged combustion techniques include low NO_x burners, flue gas recirculation, overfire air, burners out of service, and combinations of these. A collateral impact of staged combustion is an increase in emissions of products of incomplete combustion including CO, VOC and carbon in ash (referred to as Loss on Ignition, or LOI).

SCONOx

SCONOx is a NO_x adsorption/desorption technology that has been applied to combustion turbines that fire natural gas. This technology is extremely sensitive to the presence of sulfur in flue gas and could not be applied to coal-fired boilers. SCONOx is therefore determined to be not technically feasible for application to the proposed PC boilers and is not evaluated further in this analysis.

Gas Reburn

Natural gas reburn is a control technique that has shown promise as a potential retrofit to existing boilers, and may be capable of reducing emissions of NO_x to 0.015 lb/MMBtu simply by starving the coal burners for excess oxygen and completing combustion with 12-15% gas in the upper furnace. Application of this technology assumes that natural gas in substantial quantity is already available on site – otherwise it is technically infeasible. In any event, the level of NO_x control that may be achieved is less than for the other add-on control technologies and therefore it is not considered further in this analysis.

4.2.1.5 Summary of Pulverized Coal-fired Boiler BACT for NO_x

Based on a review of available control technologies for emissions of NO_x from a pulverized coal-fired boiler, we conclude that the lowest emission rate that can be achieved is 0.07 lb/MMBtu. This emission rate represents the best emissions control technology available for the proposed PC boilers, and therefore represents Lowest Achievable Emission Rate (LAER) as well as top-down BACT. No adverse cost, energy, or environmental impacts have been identified that would prevent achieving 0.07 lb/MMBtu. Therefore, STEAG proposes to achieve a NO_x BACT emission rate of 0.07 lb/MMBtu by using low-NO_x burners and selective catalytic reduction.

4.2.2 Auxiliary Boilers

The project includes three small auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. Operation of the boilers will be limited to an average of 2,000 hour/year per boiler. NO_x emissions will be controlled by only burning low sulfur distillate oil and using low NO_x burners. Based on review of recent permits for similar boilers and EPA's RACT/BACT/LAER Clearinghouse the top level of control or lowest NO_x emission rate of an auxiliary oil fired boiler is 0.10 lb/MMBtu. Steag proposes 0.1 lb/MMBtu as BACT for the auxiliary oil-fired boilers.

4.2.3 Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not operate for more than 500 hour/year each. NO_x emissions during operation will be controlled by only burning low sulfur distillate oil and ignition timing retard with turbocharging and aftercooling. Based on review of recent permits for similar emergency diesel engines and EPA's RACT/BACT/LAER Clearinghouse the top level of control or lowest NO_x emission rate approximately 6.5 g/hp-hr. Steag proposes 6.5 g/hp-hr as BACT for the emergency diesel engines.

4.3 BACT for Sulfur Dioxide

4.3.1 Pulverized Coal-fired Boilers

4.3.1.1 Formation

Emissions of sulfur dioxide are generated in fossil fuel-fired sources from the oxidation of sulfur present in the fuel. Approximately 98% of sulfur in solid fuels are emitted upon combustion as gaseous sulfur oxides. Uncontrolled emissions of SO_2 are thus affected by fuel sulfur content alone, and not by the firing mechanism, boiler size, or operation. Many coal-fired boilers in the U.S. limit emissions of SO_2 through the use of low sulfur western coals. Compared with a high sulfur eastern bituminous coal, that may contain as much as 4% sulfur, burning western coal can reduce SO_2 emissions by approximately 70% to 90%. The selection of coal type and sulfur content is therefore an important aspect of the determination of BACT and needs to be considered in conjunction with add-on control alternatives when performing the top-down analysis.

4.3.1.2 Ranking of Available Add-On Control Techniques

Generally, there are two types of add-on control for a coal-fired boiler: in-situ combustion control (sorbent injection) and post-combustion control (flue gas desulfurization). In-situ control may be used in a PC boiler by using limestone injection into the furnace, however the level of control that is achievable is not comparable to post-combustion SO_2 control systems. Post-combustion controls applicable to PC boilers are a wet scrubbing system or spray dryer absorber (SDA) using reagents such as lime, limestone, sodium bicarbonate or magnesium oxide.

A ranking of available SO_2 control technologies must take into consideration multiple variables including coal sulfur content, % removal and the resulting emission rate (lb./MMBtu) in addition to collateral impacts on other pollutants, energy impacts, and other environmental impacts (Table 4-2).

Table 4-2
Ranking of Sulfur Dioxide Technologies for Pulverized Coal Boilers

Control Technology	Typical Level of Control[1]	Typical Emission Level[1] (lb/MMBtu)	Technically Feasible for PC Boilers?
Wet Scrubber	80-98%	Depends on Coal sulfur content (lower with western coal)	Yes
Limestone Injection	25-35%	Depends on Coal sulfur content (lower with western coal)	Yes
Spray Dryer Absorber	70–92%	Depends on Coal sulfur content (lower with western coal)	Yes
Use of Low Sulfur Coal	30-90%	Western coals represent a 70-90% reduction compared with high sulfur eastern coals, lower reduction compared to other eastern coals	Yes

1. Emission levels represent steady state values. EPA AP-42 notes Limestone wet scrubbers at the high range of control efficiency are applicable to high sulfur fuels.

4.3.1.3 Recent Permit Limits

Most of the permit limits listed in EPA's RACT/BACT/LAER Clearinghouse since 1995 are in the 0.12 lb/MMBtu to 0.25 lb/MMBtu range. Many of these have compliance averaging times in the 24-hour to 30-day range. In addition, there is one permit at 0.022 lb/MMBtu and ten in the 0.086 to 0.12 lb/MMBtu range.

The lowest permit limit is 0.022 lb/MMBtu for AES-Puerto Rico. However, the economics for AES-Puerto Rico are much different than those associated with the Desert Rock project and most other projects in the continental U.S. Puerto Rico is a captive market with electricity only available from the Puerto Rico Electric Power Authority, which is a utility. When AES-Puerto Rico was permitted, oil was the only fuel being used to generate electricity. AES-Puerto Rico was built to diversify the fuel supply and provide electricity at price that would be competitive with oil fired boilers. In addition, the boilers at AES-Puerto Rico are circulating fluidized bed boilers with capacities of approximately 225 MW. For these reasons, the emission level set for AES-Puerto Rico is not considered to be the top level of control for new large coal-fired boilers in the continental U.S. This viewpoint is confirmed by the number of permits issued with higher emission rates since the original AES-Puerto Rico permit in 1998.

The two most recent permits are the Roundup Power Project in Montana (07/21/03) and the Longview Power Project in West Virginia (draft 12/04/03). Both of these projects have SO_2 permit limits of 0.12 lb/MMBtu as 24-hour averages. On a short term basis, the Longview permit limit is 0.15 lb/MMBtu as a 3-hour average and the Roundup permit is 0.15 lb/MMBtu as a 1-hour average.

4.3.1.4 SO_2 Control Technology Discussion

Wet Flue Gas Desulfurization

The most frequently utilized wet flue gas desulfurization (FED) technology is the wet limestone spray tower system. Typically, the flue gas enters at the bottom of the absorber tower, continues vertically through the limestone/water spray, passes through a mist eliminator to control the re-entrained slurry drops, and then exits the tower. Limestone (calcium carbonate) reacts with the sulfur dioxide to form calcium sulfite. The calcium sulfite may then be oxidized to form calcium sulfate, since it is easier to de-water than calcium sulfite. This can be achieved by blowing compressed air into the slurry in the retention tank in the base of the tower or in an external oxidation tank.

To fully utilize the limestone, the slurry is re-circulated through the tower and a bleed stream is taken off for de-watering. The bleed stream can be de-watered using a variety of techniques, including thickeners, centrifuges and vacuum filters. The final slurry may contain 10% to 40% water by weight.

Wet scrubbers can utilize lime rather than limestone. Some of the lime (calcium oxide) becomes calcium hydroxide in water. The slurry of calcium hydroxide and lime is fed to the spray tower. Since the cost of limestone is much less than lime, the limestone alternative is much more common. This is especially the case for medium to high sulfur coals.

Spray Dryer Absorber

The spray dryer absorber is located upstream of the particulate collection system. The flue gas passes through a spray dryer vessel where it encounters a fine mist of lime slurry. The lime slurry is injected into the spray dyer absorber through either a rotary atomizer or fluid nozzles. The moisture in the droplets evaporates and reacts with the SO_2 in the flue gas to form insoluble calcium salts. The flue gas is cooled to approximately 18 to 30 °F above the adiabatic saturation of the flue gas. The calcium salts have a moisture content of approximately 2 to 3%, which falls to 1% before reaching the particulate control device. When a fabric filter is used as the particulate control device, it allows for further reaction of the lime with the sulfur in the flue gas. This is due to the layer of porous filter cake on the surface of the filter that contains the reagent that all flue gas must pass through. This allows for increased efficiency of control of sulfuric acid mist and mercury as compared to wet scrubbers.

Use of Low Sulfur Coal

Any discussion of the relative effectiveness of add on SO_2 control must also take into account the level of uncontrolled SO_2 to be handled, which is highly dependent on the sulfur content of the coal to be burned. Higher removal efficiencies tend to be more practical when there is a high concentration of SO_2 in the flue gas, and vice versa. This is reflected in a comparison of the resulting emission rate in units of lb of SO_2 per MMBtu of fuel burned (or lb of SO_2 per kW produced). For example, a proposed project with a BACT limit of 0.16 lb/MMBtu using an 80% removal control system is environmentally superior to another project with a BACT limit of 0.32 lb./MMBtu and 95% removal. For a project located in the Western U.S., BACT includes use of low sulfur western coal as a part of a strategy to limit SO_2 to BACT levels, in combination with add-on control.

4.3.1.5 Sulfur Dioxide BACT Summary

Steag is proposing to limit SO_2 emissions to 0.06 lb/MMBtu as a 30 day average and 0.09 lb/MMBtu as a 24-hour average by burning low sulfur western coal and using a wet limestone flue gas desulfurization system. This proposed emission rate is lower than any other project listed in EPA's RACT/BACT/LAER Clearinghouse, except for AES-Puerto Rico, which was previously discussed. Steag's proposed emission limit of 0.09 lb/MMBtu as a 24-hour average is much lower than the two most recent permits which are the Roundup Power Project in Montana (07/21/03) and the Longview Power Project in West Virginia (draft 12/04/03). Both of these projects have SO_2 permit limits of 0.12 lb/MMBtu as 24-hour averages or 33% higher than the proposed Project.

4.3.2 Auxiliary Boilers

The Project includes three small auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. Operation of the boilers will be limited to an average of 2,000 hour/year per boiler. SO_2 emissions will be controlled by only burning low sulfur distillate oil with a maximum sulfur content of 0.05%. No add-on SO_2 controls have ever been applied to similar sources. The burning of low sulfur fuels such as low sulfur distillate oil is the only available SO_2 control option and is the top level of control. Therefore, Steag proposes to only burn low sulfur distillate oil (0.05% sulfur maximum) as BACT for the diesel engines

4.3.3 Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 500 hour/year each. No add-on SO_2 controls have ever been applied to similar sources. The burning of low sulfur fuels such as low sulfur distillate oil is the only available SO_2 control option and is the top level of control. Therefore, Steag proposes to only burn low sulfur distillate oil (0.05% sulfur maximum) as BACT for the diesel engines.

4.4 BACT for Carbon Monoxide

4.4.1 Pulverized Coal-fired Boilers

4.4.1.1 Formation of CO Emissions

Carbon monoxide is formed as a result of incomplete combustion of a hydrocarbon fuel. Control of CO is accomplished by providing adequate fuel residence time, excess oxygen and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through combustion modification techniques such as gas reburn can result in higher levels of CO formation. Thus, a compromise is established to achieve the lowest NO_x formation rate possible while keeping CO emission rates at acceptable levels.

4.4.1.2 Ranking of Available CO Control Technology Options

CO emissions from pulverized coal-fired boilers are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. All pulverized coal-fired boilers identified utilize front-end methods such as good combustion control wherein CO formation is suppressed within the boiler. All listings in EPA's RACT/BACT/LAER Clearinghouse for pulverized coal-fired boilers utilize combustion control techniques for CO. While gas-fired combustion turbines have been widely equipped with oxidation catalyst control technology, this technology is not applicable to coal-fired boilers. In addition to oxidizing CO, an oxidation catalyst would oxidize SO_2 to produce SO_3, which would form sulfuric acid mist emissions. Typically, the SO_2 oxidation rate would be 5% or more resulting in very high sulfuric acid mist emissions if an oxidation catalyst was applied to a coal-fired boiler.

BACT for the recently permitted Roundup Power project in Montana was approved in July 2003 as 0.15 lb/MMBtu. In December 2003, a BACT emission limit of 0.11 lb/MMBtu was approved for the Longview Power project in West Virginia. EPA's RACT/BACT/LAER Clearinghouse lists more than 30 permits in the 0.10 lb/MMBtu to 0.15 lb/MMBtu range and only one less than 0.10 lb/MMBtu. The one facility lower than 0.10 lb/MMBtu, Reliant Energy West Parish, has a NO_x emission limit of 0.5 lb/MMBtu. The low CO emission limit for this one facility may be related to a high NO_x emission rate.

A review of EPA's RACT/BACT/LAER Clearinghouse, and ENSR's review of recent permit decisions, indicates levels of CO control which may be achieved for coal-fired boilers. Emission levels and control technologies have been identified and ranked in Table 4-3.

Table 4-3
Ranking of CO Control Technology Options for Pulverized Coal-fired Boilers

Control Technology Option	Emission Level (lb/MMBtu)	Technically Feasibility for Pulverized Coal-fired Boilers?
Combustion controls	0.05 to 0.15	Yes
Oxidation catalyst	Not determined	No
SCONOx	Not determined	No

4.4.1.3 CO Control Technology Discussion

Combustion Control

Combustion control refers to controlling emissions of CO through the design and operation of the boiler in a manner so as to limit CO formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: providing sufficient excess air, staged combustion to complete burn out of products of incomplete combustion, sufficient residence time, and good mixing. All of these factors also tend to reduce emissions of VOC as well as CO. However, this process must be optimized with the efforts to reduce NO_x emissions, which may increase when steps to lower CO are taken.

Catalytic Oxidation

Catalytic oxidation is the technology that has been used to obtain the most stringent control level for CO from natural gas-fired turbine combustion units. This technology has never been applied to a coal-fired unit. It is evaluated here to determine if it could be considered transferable technology for application to the proposed pulverized coal-fired boiler. In this alternative, a catalyst would be situated in the flue gas stream to lower the activation energy required to convert products of incomplete combustion (CO and VOC) in the presence of oxygen (O_2) to carbon dioxide and water. The catalyst permits combination of the reactant species at lower gas temperatures and residence times than would be required for uncatalyzed oxidation.

The catalyst would have to be located at a point where the gas temperature is within an acceptable range. The effective temperature range for CO oxidation is between 600 °F and about 1,000 °F. Catalyst non-selectivity is a problem for sulfur containing fuels such as coal. Catalysts promote oxidation of SO_2 to SO_3 as well as CO to CO_2. The amount of SO_2 conversion is a function of temperature and catalyst design. Under optimum conditions, formation of SO_3 can be minimized to 5% of inlet SO_2. This level of conversion would result in a large collateral increase in H_2SO_4 emissions which aside from the increased ambient air impacts, could result in unacceptable amounts of corrosion to the fabric filter particulate collector, air preheater, ductwork and stack.

Oxidation catalysts are known to be extremely sensitive to potential masking, blinding or poisoning due to trace elements such as metals in flue gas. While natural gas contains essentially no trace metals, coal contains many of trace compounds within the inert fraction referred to as ash. These trace compounds are highly variable in concentration even from coal taken within the same mine or seam. There is no empirical evidence available to show that oxidation catalyst technology would actually work with coal-fired boilers, or if so what the life of the catalyst might be.

ENSR contacted an oxidation catalyst system vendor to determine the technical feasibility of installing this system on a coal-fired boiler. Due to the high particulate loading of the flue gas, variable trace element concentration in the flue gas and the SO_2 loading before air pollution control systems, the vendor stated that they could not provide a catalyst system for coal-fired applications. Consequently, oxidation catalyst systems are considered technically infeasible for application to the proposed coal-fired boilers.

SCONOx

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

4.4.1.4 Summary of BACT for CO

The only practical or demonstrated in practice measures to control CO from coal-fired boilers is good combustion. Combustion control, and the resulting optimized emission rate to minimize formation of CO while also minimizing NO_x, therefore represents BACT for the proposed boilers. Steag is proposing a limit of 0.10 lb/MMBtu that is consistent with almost all of the lowest permitted emission rates and lower than the very recent Roundup and Longview projects which were permitted in the 0.11 lb/MMBtu to 0.15 lb/MMBtu range.

4.4.2 Auxiliary Boilers

The Project includes three small auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. Operation of the boilers will be limited to an average of 2,000 hour/year per boiler. A BACT limit for CO emissions of 0.036 lb/MMBtu is proposed for these boilers based on the lowest emission limits listed in EPA's RACT/BACT/LAER Clearinghouse.

4.4.3 Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 500 hour/year each. A BACT emission limit for these diesel engines of 0.5 g/hp-hr is proposed based on data from engine manufacturers.

4.5 BACT for VOC

4.5.1 Pulverized Coal-fired Boilers

4.5.1.1 Formation of VOC Emissions

VOCs are also emitted from coal-fired boilers as a result of incomplete combustion of the fuel. Control of incomplete combustion is accomplished in the same way CO emissions are controlled: by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

4.5.1.2 Ranking of Available VOC Control Technology Options

VOC emissions from coal-fired boilers are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. All coal-fired boilers identified utilize front-end methods such as combustion control wherein VOC formation is suppressed within the boiler. All listings in EPA's RACT/BACT/LAER Clearinghouse for coal-fired boilers utilize combustion control techniques for VOC. While gas-fired combustion turbines have been widely equipped with oxidation catalyst control technology, this technology is not applicable to coal-fired boilers as previously discussed.

4.5.1.3 Recent Permit Limits

BACT for the recently permitted Roundup Power project in Montana was approved in July 2003 as 0.003 lb/MMBtu. In December 2003, a BACT emission limit of 0.004 lb/MMBtu was approved for the Longview Power project in West Virginia. EPA's RACT/BACT/LAER Clearinghouse lists more 5 permits below 0.004 lb/MMBtu, 20 permits in the 0.005 lb/MMBtu to 0.01 lb/MMBtu range and several higher permit limits.

A review of EPA's RACT/BACT/LAER Clearinghouse, and ENSR's review of recent permit decisions, indicates levels of VOC control, which may be achieved for pulverized coal-fired boilers. Emission levels and control technologies have been identified and ranked in Table 4-4.

Table 4-4
Ranking of VOC Control Technology Options for Pulverized Coal-fired Boilers

Control Technology Option	Emission Level (lb/MMBtu)	Technically Feasibility for Pulverized Coal-fired Boilers?
Combustion controls	0.002 to 0.01 (LAER)	Yes
Oxidation catalyst	Not determined	No
SCONOx	Not determined	No

4.5.1.4 VOC Control Technology Discussion

Combustion Control

Combustion control refers to controlling emissions of VOC is through the design and operation of the boiler in a manner so as to limit VOC formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: providing sufficient excess air, staged combustion to complete burn out of products of incomplete combustion, sufficient residence time, and good mixing. All of these factors also have the by-product of reducing the emissions of CO. Pulverized coal-fired boilers are designed specifically for efficient fuel combustion with thorough mixing and residence time at temperature, plus staged combustion. This level of combustion control represents BACT for the proposed boilers.

Add-On Emission Controls

Catalytic oxidation and SCONOx are not applicable to coal-fired boilers as previously discussed in Section 4.4.1.3.

4.5.1.5 Summary of BACT for VOC

The only practical or demonstrated in practice measures to control VOCs from coal-fired boilers is good combustion. Combustion control, and the resulting optimized emission rate to minimize formation of VOC while also minimizing NO_x, therefore represents BACT for the proposed boilers. VOCs are only emitted in trace and variable quantities from large high efficiency coal-fired boilers. Steag is proposing a limit of 0.0043 lb/MMBtu, which is the same as the lowest emission rate in recent permits and is lower than most new coa-fired power plants.

4.5.2 Auxiliary Boilers

The project includes three small auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. Operation of the boilers will be limited to an average of 2,000 hour/year per boiler. A BACT limit for VOC emissions of 0.0024 lb/MMBtu is proposed for these boilers based on EPA emission factors in AP-42.

4.5.3 Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 500 hour/year each. A BACT emission limit for these diesel engines of 0.3 g/hp-hr is proposed based on EPA emission factors in AP-42.

4.6 BACT for Particulate Matter and PM_{10}

4.6.1 Pulverized Coal-fired Boilers

4.6.1.1 Formation of Particulate Matter

The composition and amount of particulate matter emitted from coal-fired boilers are a function of firing configuration, boiler operation, coal properties and emission controls. Particulate matter will be emitted from the pulverized coal-fired boilers as a result of entrainment of incombustible inert matter (ash) and condensable substances such as acid gases.

4.6.1.2 Ranking of Available Particulate Control Technology Options

PM_{10} emissions limits in most permits are difficult to assess as many permits do not specify test methods and many emission limits only reflect filterable PM_{10} and do not include condensibles PM_{10}. The permit for AES-PR addressed this issue in detail. AES's permit limits filterable PM_{10} to 0.015 lb/MMBtu and allows stack testing to determine an achievable PM_{10} emission limit. Stack tests showed that filterable PM_{10} emissions were below 0.015 lb/MMBtu. However, based on stack test results, AES has applied for an administrative change to their permit to set the total PM_{10} emission limit at 0.03 lb/MMBtu. The permits for Energy Services of Manitowoc contains a limit of 0.011 lb/MMBtu, purported to include front and back half PM_{10}. However, this project has yet to be built or tested and ability to comply with such a limit is very questionable. Several other recent coal-fired boiler projects are listed with emission rates in the range of 0.010 lb/MMBtu to 0.015 lb/MMBtu based on front half (filterable) PM only, and this level is representative of BACT and LAER for PM and filterable PM_{10} emissions from this source category.

A review of EPA's RACT/BACT/LAER Clearinghouse indicates several levels of particulate control, which may be achieved for pulverized boilers. Emission levels and control technologies have been identified and ranked in Table 4-5.

Table 4-5
Ranking of Particulate Control Technology Options for Pulverized Coal-fired Boilers

Control Technology Option	Emission Level (lb/MMBtu)	Technically Feasibility for Pulverized Coal-fired Boilers?
Fabric Filter	0.01 to 0.02 for filterable PM	Yes
Electrostatic precipitator	0.015 to 0.025 for filterable PM	Yes
High energy wet scrubber	Not determined	No applications in the last 15 years to large coal-fired boilers
Emission levels represent target steady-state values at base load, for front-half (filterable) only. Inclusion of the condensable fraction is through to double the particulate emission rate for coal-fired boilers.		

There are almost 50 coal-fired boilers listed in the EPA's BACT/LAER Clearinghouse with emission limits for particulate matter that are less than or equal to 0.02 lb/MMBtu. All but one of these listings report that a fabric filter is utilized for control of particulate matter (the AES Puerto Rico facility is the only exception). The control of PM using fabric filtration is clearly demonstrated for coal-fired boilers.

Wet control techniques (venturi or other high-energy scrubbers), on the other hand, do not represent a recently applied or demonstrated control technique for coal-fired boilers and do not offer more stringent levels of control of particulate matter than fabric filters.

4.6.1.3 PM10 Control Technology Discussion

Fabric Filter

Fabric filters are widely used for particulate control from PC boilers and are capable of over 99% control efficiency. According to EPA’s Fabric Filter Fact sheet (US EPA, 2000), “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 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 13 to 31 centimeters (cm) (5 to 12 inches) in diameter. Groups of bags are placed in isolatable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

The advantages of fabric filters include:

1) High collection efficiency for a broad range of particle sizes;

2) Flexibility in design (various methods of cleaning methods and filter media);

3) Wide range of volumetric capacities;

4) Reasonable pressure drops and power requirements; and

5) Handles a wide range of solid materials.

Some disadvantages of fabric filters are as follows:

1) Danger of explosion in the presence of a spark; or catastrophic bag damage due to fire; and

2) Wet particles can agglomerate on a filter cloth if the waste gases are at a temperature close to their dew point.

4.6.1.4 Summary of BACT for Particulate Matter

Fabric filters and ESP's represent technically feasible options for the control of particulate matter from coal-fired boilers. Wet control techniques (scrubbers), on the other hand, do not represent a demonstrated control technique and do not offer more stringent levels of control of particulate matter than fabric filters.

Based on numerous projects using fabric filters, Steag proposes to use a fabric filter as BACT to limit PM and filterable PM_{10} emissions to 0.012 lb/MMBtu and total PM_{10} (including condensable PM_{10}) emissions to 0.02 lb/MMBtu. The proposed PM and filterable PM_{10} emission rates are equal to the lowest emission level for a PC unit (Wygen 2 in Wyoming) listed in EPA's RACT/BACT/LAER Clearinghouse. Very little data are available on condensable PM_{10} emissions from western coal (or any) coal-fired boilers, and for that reason Steag proposes a condensable PM_{10} limit of 0.02 lb/MMBtu as BACT for total PM_{10}, but requests a trial period of three years to determine the feasibility of this exceptionally low limit.

4.6.2 Auxiliary Boilers

The project includes three small auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. Operation of the boilers will be limited to an average of 2,000 hour/year per boiler. A BACT limit for PM_{10} emissions including condensable PM_{10} of 0.10 lb/MMBtu is proposed for these boilers based on Steag design data.

4.6.3 Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 500 hour/year each. A BACT emission limit for PM_{10} emissions including condensable PM_{10} of 0.22 g/hp-hr is proposed based for these diesel engines on EPA emission factors in AP-42.

4.6.4 Material Handling Sources

Material handling sources will be controlled by dust suppression systems, enclosures or fabric filters. For example, conveyors will be totally enclosed in order to eliminate emissions. Fabric filters will be used to control other sources. BACT for the fabric filters is proposed as 0.01 gr/dscf. This proposed emission limit is the same as the BACT limit of 0.01 gr/dscf, which was issued for the Roundup Power project in July 2003.

4.7 BACT for Sulfuric Acid Mist

4.7.1 Pulverized Coal-fired Boilers

Emissions of sulfuric acid mist are generated in fossil fuel-fired sources from the oxidation of sulfur present in the fuel. The amounts of sulfur or SO_2 that are oxidized to sulfuric acid mist may affected by trace metal catalysis.

The Project will control sulfuric acid mist emissions through the use low sulfur western coal, injection of hydrated lime before the fabric, fabric filtration and wet limestone scrubbing. Steag is proposing a sulfuric acid mist emission rate of 0.0049 lb/MMBtu as BACT. This emission rate is as low as some recent BACT decisions such as the Thoroughbred Generating Station in Kentucky. In addition, it is lower than the July 2003 permit of 0.0064 lb/MMBtu for the Roundup Power Project in Montana.

4.7.2 Auxiliary Boilers and Diesel Generators

BACT for the auxiliary boilers and diesel engines is the use of low sulfur (0.05% S) distillate oil.

4.8 BACT for Hydrogen Fluoride

Emissions of hydrogen fluoride are generated in fossil fuel-fired sources from the oxidation of fluorine present in the fuel. The Project will control hydrogen fluoride emissions through the injection of hydrated lime before the fabric, fabric filtration and wet limestone scrubbing. Steag is proposing a hydrogen fluoride emission rate of 0.00024 lb/MMBtu based on an assumed concentration of fluorine in the coal of 100 ppm and a 98% control as BACT. This emission rate is consistent with recent BACT decisions.

4.9 BACT for Lead

Emissions of lead are generated in fossil fuel-fired sources from the lead present in the fuel. The Project will control lead emissions using fabric filtration (baghouse) on the PC boilers to achieve BACT for PM_{10} emissions.

4.10 Summary of BACT Emission Levels

Table 4-6
Summary of Proposed BACT Emission Limits

Pollutant	Emissions Limit (lb/MMBtu)	Control Technology
Pulverized Coal-fired Boilers		
NO_x	0.07	Low-NO_x burner and SCR
SO_2	0.06 as a 30 day rolling average and 0.09 as a 24-hour average	Low sulfur western coal, hydrated lime injection before the fabric filter, and wet limestone desulfurization
CO	0.10	Good combustion practices
VOC	0.003	Good combustion practices
PM/PM_{10}	0.02 (total)	Baghouse
Pb and Be	No limit specified	Baghouse
H_2SO_4	0.0049	Low sulfur western coal, hydrated lime injection before the fabric filter, and wet limestone desulfurization
HF	0.0024	Hydrated lime injection before the fabric filter, and wet limestone desulfurization
Materials handling systems		
PM/PM_{10}	0.01 gr/dscf for fabric filters	Enclosures, dust suppression, and fabric filters
Auxiliary Boilers		
NO_x	0.1	Low-NO_x burners
SO_2	0.05	Low sulfur distillate oil (0.05% S)
CO	0.036	Good combustion
VOC	0.0024	Good Combustion
PM/PM_{10}	0.024	Low sulfur distillate oil and good combustion
Emergency Generator and Firewater Pump		
NO_x	6.5 g/hp-hr	Ignition timing retard, turbo-charging and after-cooling
SO_2	0.19 g/hp-hr	Low sulfur distillate oil (0.05% S)
CO	0.5 g/hp-hr	Good combustion
VOC	0.3 g/hp-hr	Good combustion
PM/PM_{10}	0.22 g/hp-hr	Low sulfur distillate oil and good combustion

4.11 Maximum Achievable Control Technology (MACT)

The Project will be a major source of Hazardous Air Pollutants (HAP). Since the MACT standard for coal-fired boilers has not been finalized, this application presents a case-by-case MACT analysis as required by Section 112 (g) of the Clean Air Act for control of HAP emissions. The analysis addresses: (1) non-mercury metallic HAP emissions, (2) mercury emissions, acid gases (hydrogen chloride and hydrogen fluoride), and organic HAPs.

Non-mercury metallic HAPs will be emitted as part of the particulate emissions from coal combustion. The Project will use a fabric filter to limit PM emission to 0.02 lb/MMBtu. The proposed PM emission rate is the lowest permitted emission rate for a coal-fired boiler and is, therefore, equivalent to the Lowest Achievable Emission Rate (LAER). EPA has used PM emission limits as surrogates for control of HAP metal emissions. In addition, EPA has stated that a strong correlation exists between metallic HAP emissions and PM emissions and that good control of PM provides good control of metallic HAPs. Therefore, the proposed fabric filter and PM emission rate represent MACT for non-mercury metallic HAPs.

EPA's proposals for mercury control are in a state of flux. Steag expects to achieve an 80% reduction in mercury through the combination of emission controls proposed for the Project and based on the coal supply proposed.

Hydrogen chloride and hydrogen fluoride will be controlled by injection of hydrated lime before the fabric filer and wet limestone scrubbing. HCI will be controlled to less than 0.003 lb/MMBtu. Control efficiencies of at least 98% for HF are expected. The proposed emissions controls, emission limits and high control efficiencies represent a case-by-case MACT level for HCI and HF.

Organic HAP emissions will be controlled by good combustion to limit CO and VOC emissions. High combustion efficiency as shown by the BACT emission rates for CO and VOC represents MACT for organic HAP emissions.

5.0 PROJECT EMISSIONS

Potential criteria emissions are summarized in Section 5.1. Startup and shutdown emission are discussed in Section 5.2. Potential emissions of hazardous air pollutants are summarized in Section 5.3. Emission rates are based on preliminary plant design data from Steag Encotec, other vendor data, and EPA emission factors from AP-42. Detailed emission calculations and stack parameters for each source are presented in Attachment 3.

5.1 Criteria Pollutant Emissions

Emissions of all criteria pollutants from all sources are controlled by applying BACT. Maximum annual criteria pollutant emission rates are summarized in Table 5-1. The two 750 MW boilers are the largest emission sources.

Table 5-1
Summary of Criteria Pollutant Maximum Potential Emissions

Pollutant	PC Boilers (tpy)	Auxiliary Boilers (tpy)	Emergency Generators (tpy)	Fire Water Pumps (tpy)	Material Handling (tpy)	Storage Tanks (tpy)	Project PTE (tpy)
CO	5,957	9.26	0.87	0.16	n/a	n/a	5,967
NO_x	4,170	25.92	11.3	2.04	n/a	n/a	4,209
SO_2	3,574	13.15	0.34	0.06	n/a	n/a	3,588
PM	714.8	3.70	0.41	0.07	13.1	n/a	732
PM_{10}	1,191	6.11	0.38	0.07	10.0	n/a	1,208
VOC	178.7	0.63	0.53	0.10	n/a	0.14	180.1
Lead	11.9	0.00233	0.00006	0.00001	n/a	n/a	11.9
Fluorides	14.3	neg	neg	neg	n/a	n/a	14.3
H_2SO_4	291.9	0.23	0.01	0.0009	n/a	n/a	292.1
Hydrogen Sulfide	neg	neg	neg	neg	n/a	n/a	neg
Total Reduced Sulfur	neg	neg	neg	neg	n/a	n/a	neg
Reduced Sulfur Compounds	neg	neg	neg	neg	n/a	n/a	neg
n/a – not applicable, neg. – negligible							

5.2 Startup and Shutdown Emissions

Startup and shutdown procedures for the pulverized coal-fired boilers are designed to provide for equipment protection while minimizing emissions. Startup duration is dictated by the need to gradually warm up refractory materials, metal surfaces, and the 750 MW steam turbine. Startups are defined as cold, warm and hot to account for the amount of latent heat still in the boiler. The different starts are defined by the amount of time the boiler has been down. Cold starts are defined as starts after the boiler has been down for more than 72 hours, warm starts more than 8 hours and less than 24 hours and cold starts less than 8 hours. The time required to safely bring each boiler up is defined below.

- 6.5 hours for a cold start;
- 4.0 hours for a warm start; and
- 2.6 hours for a hot start.

It is just as important not to cool the boiler down too fast. A shutdown will require 3.3 hour.

The maximum number of startups is anticipated to be 60 per year, an average of 30 per boiler (4 cold, 10 warm and 16 hot). Startup and shutdown operations do not result in any excess daily or annual emissions compared to normal continuous operation.

The facility design includes three 86.4 MMBtu/hour boilers, equipped with superheaters, burning low sulfur distillate oil (0.05% sulfur) to provide steam to assist with reducing the time for startup of the main boilers by preheating key areas. When the flue gas temperature exceeds 600°F (320°C), which typically approximates a boiler load of 40%, the SCR system is placed in service and startup is complete. The SCR will not function at temperatures below 600°F (320°C).

During a cold start, the one of more auxiliary boilers will start providing steam to the main boiler and/or the steam turbine at least one hour before any fuel is fired in the main boiler. For the next 4.5 hours, boiler equipment will be gradually warmed up using steam from the auxiliary boilers and by firing low sulfur distillate oil (0.05%) in the main boiler. During the last hour, the auxiliary boiler will continue to operate while pulverized coal feeding is started and gradually increased until the boiler reaches 40% load completing startup.

A warm start requires less time than a cold start because the equipment is hotter and thermal stresses are reduced. For a warm start, one of more auxiliary boilers will start providing steam to the main boiler and/or the steam turbine approximately one hour before any fuel is fired in the main boiler. For the next 2 hours, boiler equipment will be gradually warmed up using steam from the auxiliary boilers and by firing low sulfur distillate oil (0.05%) in the main boiler. During the last hour, the auxiliary boiler will continue to operate while pulverized coal feeding is started and gradually increased until the boiler reaches 40% load completing startup.

A hot start only requires 2.6 hours because the equipment is relatively hot and thermal stresses are reduced. A hot start begins with firing of low sulfur distillate oil in the main boiler. After approximately 5 minutes, one of more auxiliary boilers will start providing steam to the main boiler and/or the steam turbine. After about one hour, feeding of pulverized coal will be started. For the remaining 1.6 hours, the coal feed rate will be gradually increased while the auxiliary boiler load and oil firing rate to the main boiler are decreased. During a hot start, average hourly emissions of all pollutants, except for NO_x, are less than normal full load emissions. The slightly elevated NO_x emission rates during startup are of a short duration and do not result in any long-term increase in emissions compared to normal continuous operation.

For a routine shutdown, an auxiliary boiler begins providing steam approximately 15-20 minutes before the coal feed rate is decreased below 40% load. At 40% load, the SCR is taken out of service. The coal feed rate is gradually decreased to 0% over a two hour period. Toward the middle of this period, oil firing in the main boiler is started and the auxiliary boiler continues to operate. After coal feeding stops, oil firing continues in the main boiler for about 0.5 hours. During a shutdown, average hourly emissions of all pollutants are less than normal full load emissions.

5.3 Hazardous Air Pollutant Emissions

Emissions of HAP are controlled by applying MACT. Maximum annual HAP emission rates are summarized in Table 5-2. Maximum emissions for all HAP from the project are 244.7 ton/year with the pulverized coal-fired boilers accounting for 240.7 ton/year. Hydrogen chloride emissions of 179 ton/year and hydrogen fluoride emissions of 14 ton/year account for most of the emissions from the pulverized coal-fired boilers. Hydrogen chloride also accounts for most of the HAP emissions from the auxiliary boilers.

Table 5-2
HAP Emissions Summary

Emissions Unit	HAP Emissions (tpy)
Main Boilers	240.7
Auxiliary Boilers	3.83
Emergency Generators	0.18
Diesel Fire Pumps	0.03
Total Facility HAP Emissions (tpy)	**244.7**

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 Overview

The location of the Desert Rock Energy Facility is approximately 25 - 30 miles (40 – 60 km) southwest of Farmington, New Mexico in the Four Corners Area where Arizona, Colorado, New Mexico and Utah meet. The modeling protocol provided in Attachment 1 describes the dispersion modeling procedures for determining the air quality impact of the proposed facility on nearby PSD Class I and II areas. A review of the modeling procedures is presented in Section 6.2. The Class II and Class I modeling analysis and results are described in Sections 6.3 and 6.4, respectively. Section 6.5 discusses the growth analysis. Section 6.6 provides the Soils and Vegetation analysis, and other impact issues.

6.2 Modeling Procedures

As discussed in the modeling protocol, ENSR used the CALPUFF modeling system for both the Class I PSD modeling and Class II analyses due to the presence of complex winds in the vicinity of the proposed Desert Rock Energy Facility.

ENSR used the following versions of the CALPUFF modeling system:

- CALMET version 5.2 (level 000602d),
- CALPUFF version 5.5 (level 010730_1), and
- CALPOST version 5.2 (level 991104d).

These software versions are the ones associated with the latest available user guides. Although EPA has announced the availability of 2003 versions of the CALPUFF modeling system, these are still being debugged and do not have any user's guides available.

6.2.1 Meteorological Data

The meteorological data was used as input to CALPUFF features three years of prognostic mesoscale meteorological (MM) data, as is recommended by the Guideline on Air Quality Models (Section 9.3.1.2(d)). The most advanced MM data was used, consisting of 2001-2003 hourly meteorological data archived from the Rapid Update Cycle (RUC) model. Horizontal data resolution for the RUC model is 40 kilometers for 2001 and 2002, and 20 kilometers for 2003. The Rapid Update Cycle data is referred to as "RUC40" for the 40-km resolution data and "RUC20" for the 20-km resolution data. A technical paper describing a precedent for the regulatory use of this type of data in a North Dakota CALPUFF application is provided in Appendix B of the modeling protocol.

The CALMET modeling conducted for the nearby PSD Class II areas used 1.5-km grid spacing, encompassing an area 210-km square. The CALMET modeling for the distant PSD Class II areas and the PSD Class I area encompassed a 680 km x 552 km (E-W / N-S) area with a 4-km grid element size. Details regarding the CALMET modeling are provided in the modeling protocol (Attachment 1).

6.2.2 Stack Characteristics and Emissions

The PSD Class I and II modeling analyses used emission rates presented in Tables 6-1 through 6-4, which characterize emissions from the main stack and other ancillary combustion sources associated with the plant. There are three start-up and one shutdown emissions scenarios for the facility, as described in Section 3 of the modeling protocol. All of the start-up and shutdown emissions are less than minimum load (40% load) case and have not been modeled separately.

The Class I analysis modeled the two main stacks only at 100 percent load. A SCREEN3 analysis, provided in Appendix D of the modeling protocol, indicates that the lowest (40%) load case can possibly lead to the highest near-field concentration predictions. Therefore, for the Class II analysis, we modeled the main stacks at both 40 and 100 percent (maximum and minimum) load, and also included emissions from the auxiliary boiler, the diesel generator and water pump, as well as the material-handling sources.

6.3 PSD Class II Modeling Analysis

A grid system that extends approximately 105 kilometers in all directions from the proposed source location was used in this CALPUFF modeling analysis, as shown in Figure 6-1. The total domain size of 210 kilometers was chosen because the maximum extent of the SIA is generally considered to be 50 kilometers from the proposed source location, but the high terrain in the Ute Mountains in northern New Mexico was also populated with receptors out to about 55 km. An additional buffer distance of 50 km was provided for inclusion of background sources in a possible cumulative source analysis. This design allows a 210 km x 210 km (E-W / N-S) grid with a 1.5-km grid element size. The southwest corner of the grid is located at approximately 35.55°N latitude and 109.75°W longitude.

6.3.1 Source and Receptor Locations

The proposed facility's central location is noted by the UTM coordinates of the main stack, which are 721,764 m (Easting) and 4,040,974 m (Northing) (UTM zone 12, North American Datum 1983 [NAD83]). The Lambert Conformal location of this stack is, 129.275 km (east) and 54.213 km (north), based on reference coordinates of 36° N latitude and 110° W longitude along with 30° N and 60° N as the two standard parallels. The Class II CALPUFF analysis used receptors based on this Lambert Conformal projection and the main stack as the center of the grid (see Figure 6-2). Figure 6-3 shows the near field receptor grid and fenceline. Receptors were placed along the proposed facility fence line spaced at every 50 meters. A multi-layered Cartesian grid combined with a polar grid extends out from the main stack as far as to resolve the SIA. The Cartesian receptor grid consists of 100-meter spaced receptors beyond the fenceline out to 1.5 km, 250-meter spacing was used beyond 1.5 km out to 4 km, and 500-meter spacing was used beyond 4 km out to 8 km, and 1000-meter spacing was used beyond 8 km out to 10 km. Beyond 10 km, polar grid receptors were used. The polar grid receptors were

Table 6-1
Emission Rates and Stack Parameters for Each of the Main Boilers

Plant Performance	***Units***	**100% Load**	**80% Load**	**60% Load**	**40% Load**
Full Load Heat Input to Boiler	*MMBtu/hr*	6,800	5,440	4,080	2,720
Emissions per Boiler					
SO_2 (3-hour)	*lb/MMBtu*	0.090	0.090	0.090	0.090
	g/s	77.11	61.69	46.27	30.84
SO_2 (Annual)	*lb/MMBtu*	0.060	0.060	0.060	0.060
Hourly Emissions	*g/s*	51.41	41.13	30.84	20.56
Annual Emissions	*tpy*	1787.04	1429.63	1072.22	714.82
NO_X	*lb/MMBtu*	0.070	0.070	0.070	0.070
Hourly Emissions	*g/s*	59.97	47.98	35.98	23.99
Annual Emissions	*tpy*	2084.88	1667.90	1250.93	833.95
PM_{10} Total	*lb/MMBtu*	0.020	0.020	0.020	0.020
Hourly Emissions	*g/s*	17.14	13.71	10.28	6.85
Annual Emissions	*tpy*	595.68	476.54	357.41	238.27
CO	*lb/MMBtu*	0.100	0.100	0.100	0.100
Hourly Emissions	*g/s*	85.68	68.54	51.41	34.27
Annual Emissions	*tpy*	2978.40	2382.72	1787.04	1191.36
H_2SO_4	*lb/MMBtu*	0.0049	0.0049	0.0049	0.0049
Hourly Emissions	*g/s*	4.20	3.36	2.52	1.68
Annual Emissions	*tpy*	145.94	116.75	87.56	58.38
Pb	*lb/MMBtu*	0.00020	0.00020	0.00020	0.00020
Hourly Emissions	*g/s*	0.17	0.14	0.10	0.07
Annual Emissions	*tpy*	5.96	4.77	3.57	2.38
Stack Parameters					
Stack Gas Exit Temperature	F	122	122	122	122
	K	**323.15**	**323.15**	**323.15**	**323.15**
Stack Gas Exit Velocity	ft/s	82	65.6	49.2	32.8
	m/s	**24.99**	**19.99**	**15.00**	**10.00**
Stack Height	ft	492	492	492	492
	m	**149.95**	**149.95**	**149.95**	**149.95**
Stack Diameter	ft	26.00	26.00	26.00	26.00
	m	**7.92**	**7.92**	**7.92**	**7.92**

Table 6-2
Emission Rates and Stack Parameters for the Auxiliary Steam Generator

Estimated Maximum Annual Hours of Operation:	2,000	hours/year
Stack Height:	98	feet
Stack Diameter:	4	feet
Average Stack Exit Temperature:	284	F
Stack Exit Velocity:	82	ft/s

Pollutant	Hourly Emissions			Annual Emissions	
	(lb/hr)	(g/s)	(lb/MMBtu)	(tpy)	(g/s)
CO	3.09	0.39	0.036	3.09	0.089
NO_x	8.64	1.09	0.1	8.64	0.249
PM_{10} Total	2.04	0.26	0.024	2.04	0.059
SO_2	4.38	0.55	0.051	4.38	0.126
H_2SO_4	0.076	0.010	0.00087	0.076	0.0022
Pb	0.00078	0.00010	0.000009	0.00078	0.000022

Table 6-3
Emission Rates and Stack Parameters for the Emergency Diesel Generator

Maximum Annual Hours of Operation:	500	hours/year
Stack Height:	45	Feet
Stack Diameter:	3	Feet
Stack Flow Rate:	9058	Cfm
Stack Gas Exit Temperature:	870	deg F
Stack Gas Exit Velocity:	21	ft/s

Pollutant	**Hourly Emissions**			**Annual Emissions**	
	(lb/hr)	**(g/hp-hr)**	**(g/s)**	**(tpy)**	**(g/s)**
CO	1.74	0.50	0.22	0.43	0.013
NO_x	22.61	6.50	2.85	5.65	0.163
PM_{10} Total	0.77	0.22	0.10	0.19	0.006
PM	1.34	0.38	0.17	0.33	0.010
SO_2	0.68	0.19	0.09	0.17	0.005
H_2SO_4	0.02	0.01	0.003	0.01	0.0001
Pb	1E-04	3E-05	2E-05	3E-05	9E-07

Table 6-4
Emission Rates and Stack Parameters for the Diesel Fire Fighting Pump

Maximum Annual Hours of Operation:	500	hours/year
Stack Height:	30	Feet
Stack Diameter	0.6	Feet
Stack Flow Rate:	1265	Cfm
Stack Gas Exit Temperature:	900	F
Stack Gas Exit Velocity:	74	ft/s

Pollutant	Hourly Emissions			Annual Emissions	
	(lb/hr)	(g/hp-hr)	(g/s)	(tpy)	(g/s)
CO	0.31	0.50	0.04	0.08	0.002
NO_x	4.07	6.50	0.51	1.02	0.029
PM_{10} Total	0.14	0.22	0.02	0.03	0.001
SO_2	0.12	0.19	0.02	0.03	0.001
H_2SO_4	0.004	0.01	0.0005	0.001	0.00003
Pb	2.E-05	3.E-05	3.E-06	5.E-06	2.E-07

placed along 36 10^o radials extending from the central location of the main stacks. Receptors between 10 km and 20 km were placed along each radial every 1000 meters, and from 20 km to 50 km, 5000-meter spacing were used. Additional densely spaced receptors were placed in one specific area with complex terrain (in the Ute Mountains to the north, in the direction where the proposed facility, the Four Corners Power Plant, and the San Juan Generating Station line up) to ensure resolution of the maximum impacts in that area. The near-field receptor elevations were developed from 7.5 minute (~30 meter spaced) and 10-meter spaced Digital Elevation Model (DEM) files. The polar coarse grid receptors were developed from 90-meter spaced DEM files.

Figure 6-1 Class II CALPUFF Modeling Domain

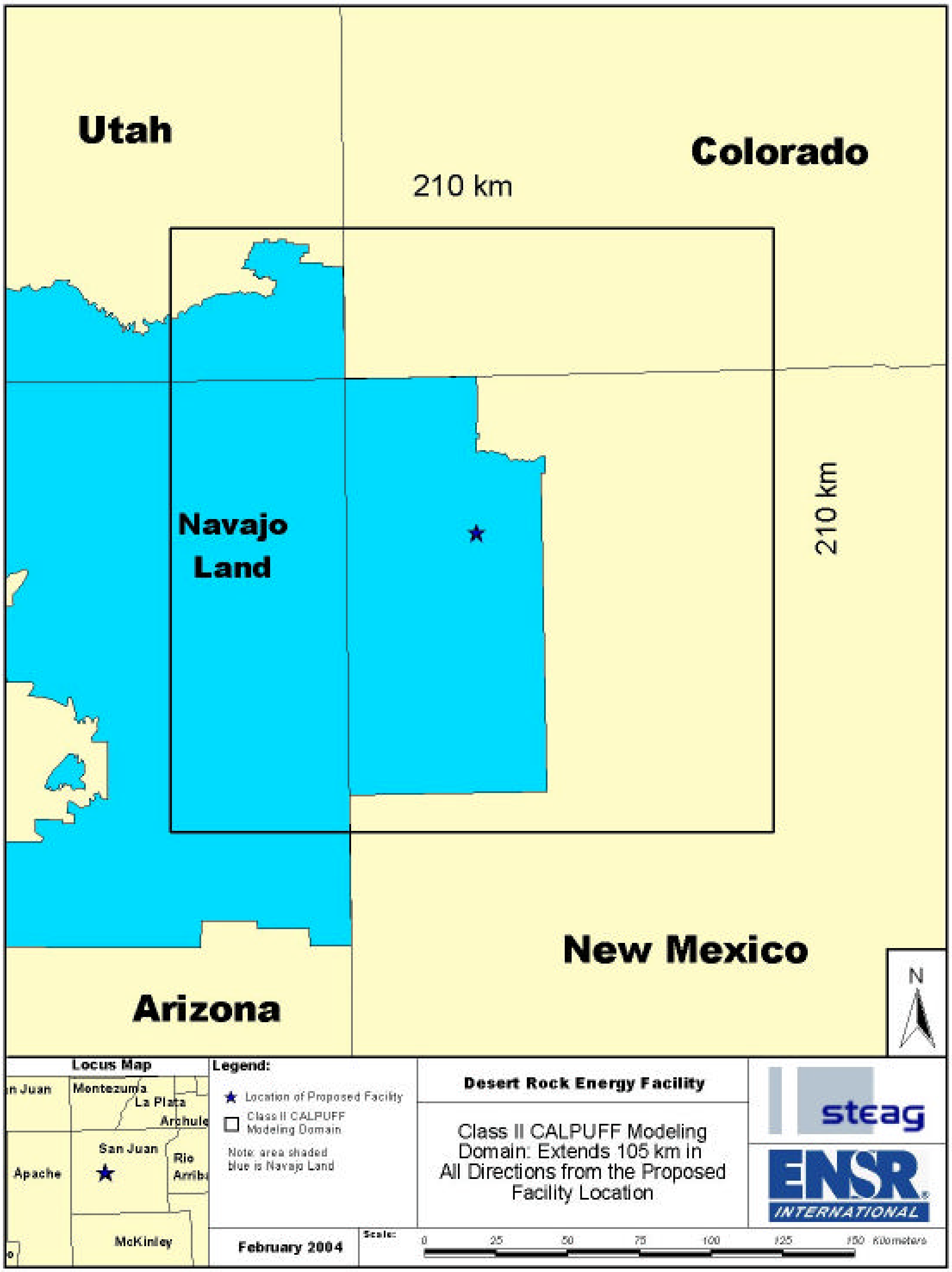


Figure 6-2 Class II Receptor Grid

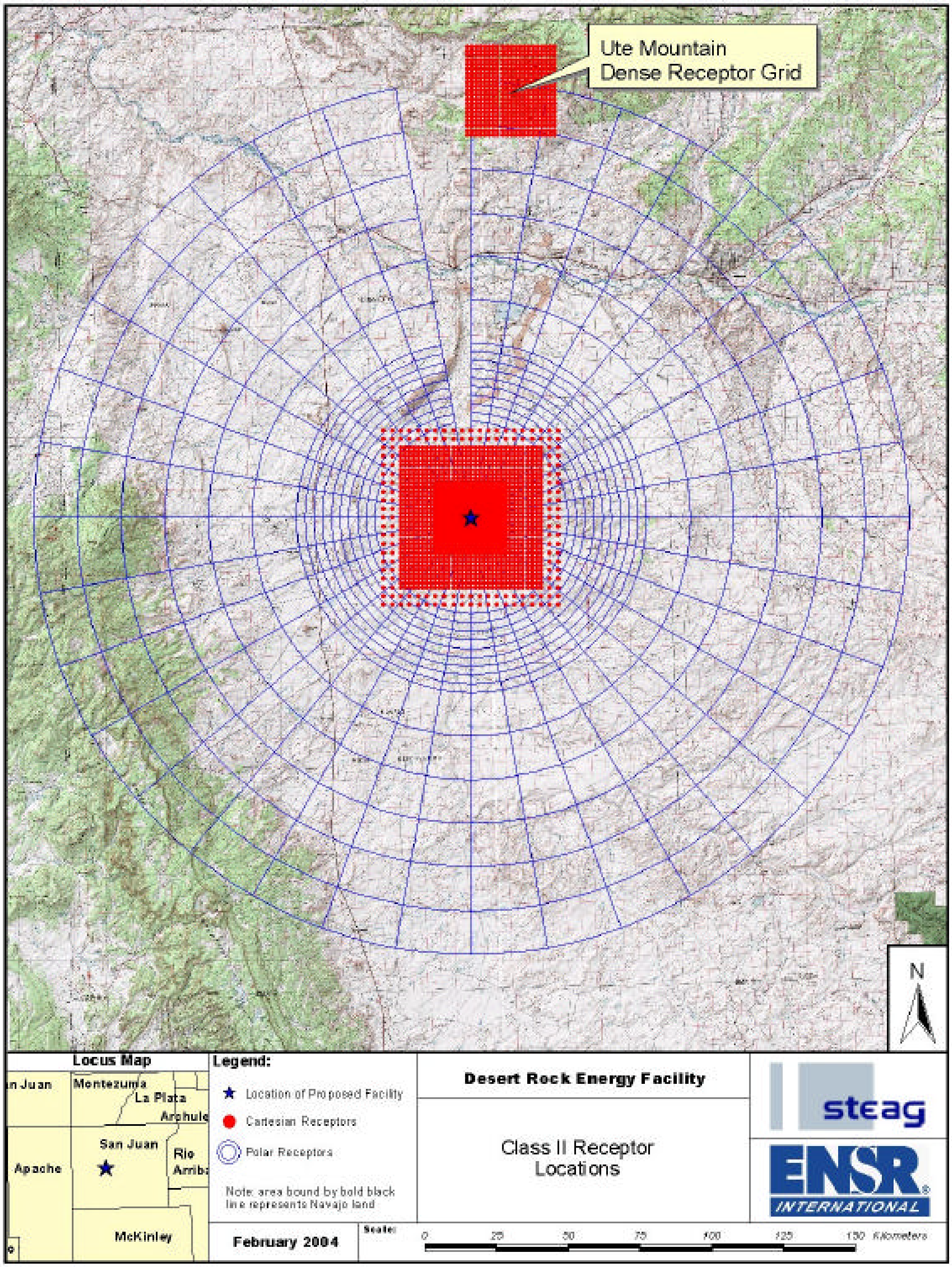
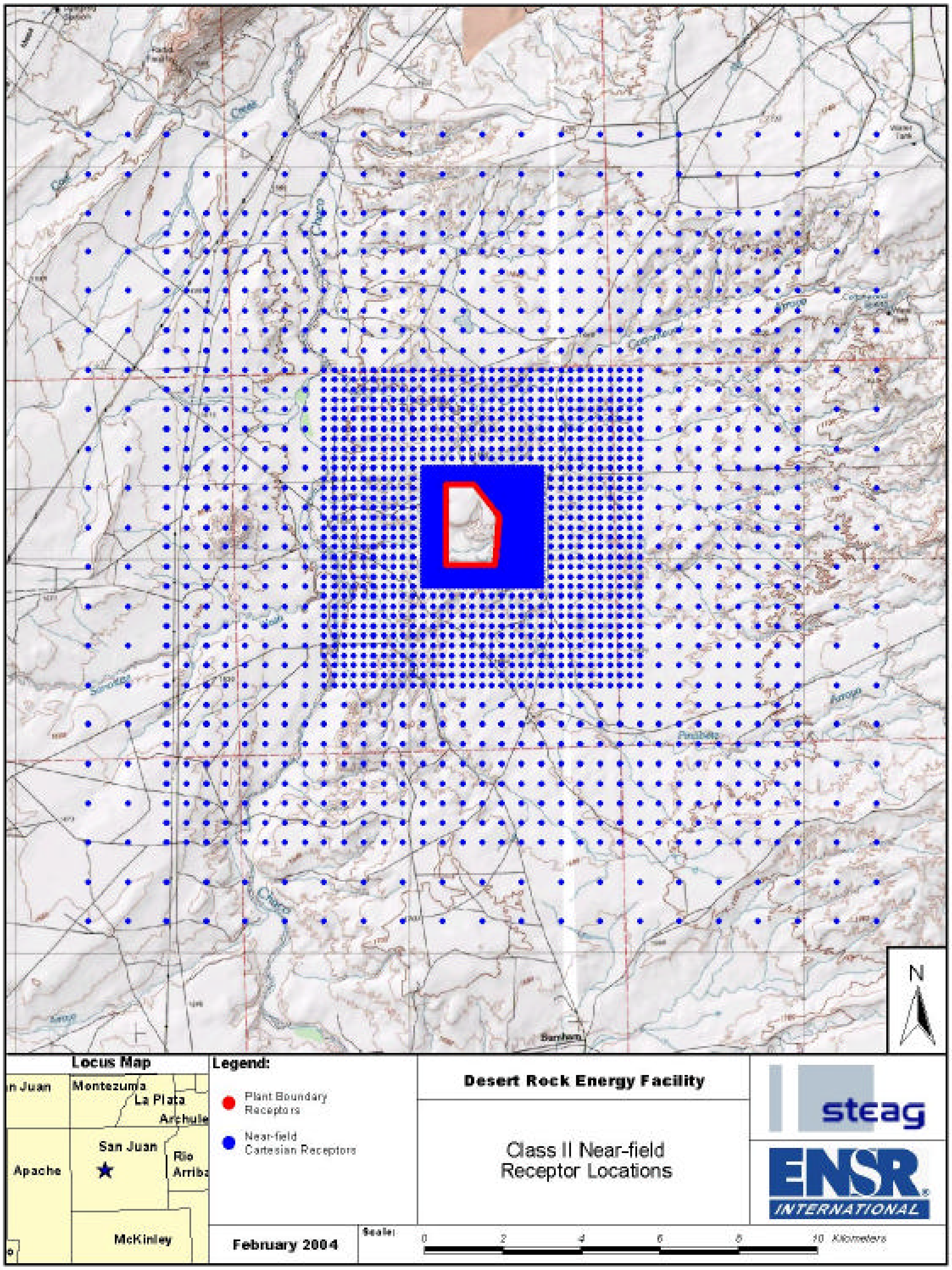


Figure 6-3 Near-Field Receptor Grid



6.3.2 Good Engineering Practice Stack Height Analysis

Federal stack height regulations limit the stack height used in performing dispersion modeling to predict the air quality impact of a source. Sources must be modeled at the actual physical stack height unless that height exceeds the Good Engineering Practice (GEP) stack height. If the physical stack height is less than the formula GEP height, the potential for the source's plume to be affected by aerodynamic wakes created by the building(s) must be evaluated in the dispersion modeling analysis.

A GEP stack height analysis was performed for all point emission sources that are subject to effects of buildings downwash at the proposed facility in accordance with the EPA's "Guideline for Determination of Good Engineering Practice Stack Height" (EPA, 1985). A GEP stack height is defined as the greater of 65 meters (213 feet), measured from the ground elevation of the stack, or the formula height (H_g), as determined from the following equation:

$$H_g = H + 1.5\,L$$

where

H is the height of the nearby structure which maximizes H_g, and

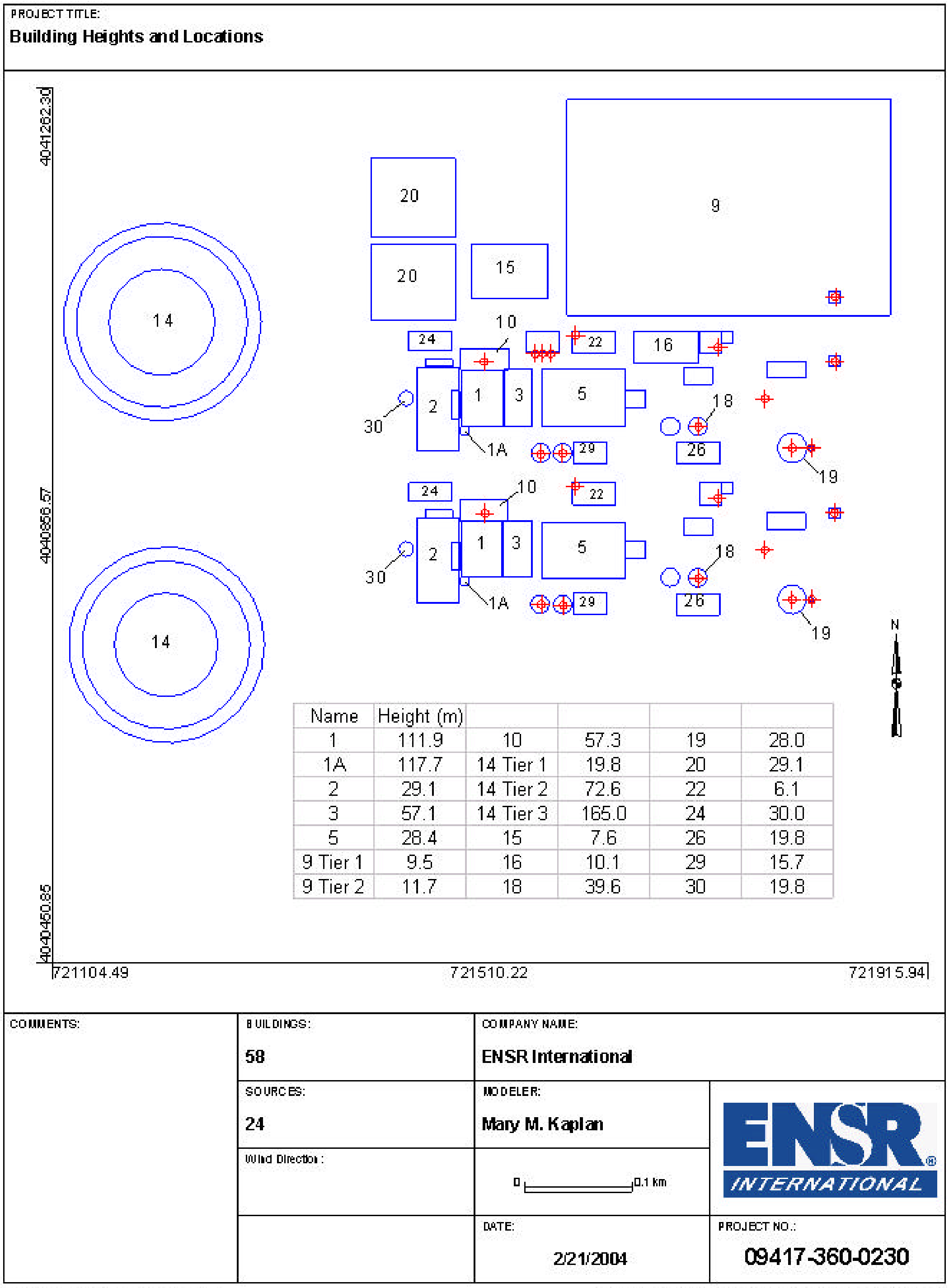
L is the lesser dimension (height or projected width) of the building.

Both the height and the width of the building are determined through a vertical cross-section perpendicular to the wind direction. In all instances, the GEP formula height is based upon the highest value of H_g as determined from H and L over all nearby buildings over the entire range of possible wind directions. For the purposes of determining the GEP formula height, only buildings within 5L of the source of interest are considered.

The GEP analysis was conducted with EPA's BPIP program, version 95086. The building-specific wind directions were used as input to CALPUFF. Figures 6-4 and 6-5 show the buildings and stacks considered in the GEP analysis. The gray areas in Figure 6-5 represent the areas modeled for the road network.

A review of the distances between each source and controlling building and the plant fenceline indicated that all potential building cavities that affect stacks would be wholly contained within the plant property. As a result, no further analysis of building cavity effects is necessary.

Figure 6-4 GEP Analysis Building Heights and Locations

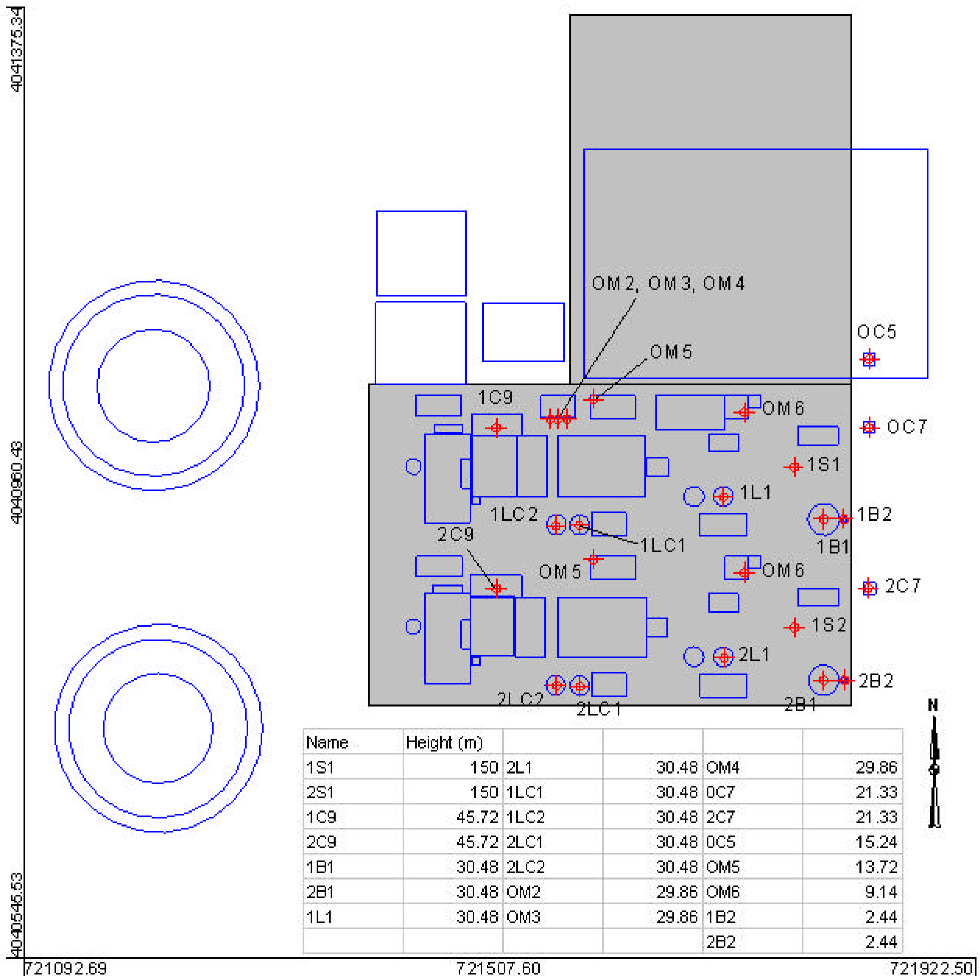


Name	Height (m)				
1	111.9	10	57.3	19	28.0
1A	117.7	14 Tier 1	19.8	20	29.1
2	29.1	14 Tier 2	72.6	22	6.1
3	57.1	14 Tier 3	165.0	24	30.0
5	28.4	15	7.6	26	19.8
9 Tier 1	9.5	16	10.1	29	15.7
9 Tier 2	11.7	18	39.6	30	19.8

Figure 6-5 GEP Analysis Stack Heights and Locations

PROJECT TITLE:

Stack Heights and Locations



Name	Height (m)				
1S1	150	2L1	30.48	OM4	29.86
2S1	150	1LC1	30.48	0C7	21.33
1C9	45.72	1LC2	30.48	2C7	21.33
2C9	45.72	2LC1	30.48	0C5	15.24
1B1	30.48	2LC2	30.48	OM5	13.72
2B1	30.48	OM2	29.86	OM6	9.14
1L1	30.48	OM3	29.86	1B2	2.44
				2B2	2.44

COMMENTS:

BUILDINGS: **58**

COMPANY NAME: **ENSR International**

SOURCES: **24**

MODELER: **Mary M. Kaplan**

Wind Direction:

0 0.1 km

ENSR INTERNATIONAL

DATE: 2/21/2004

PROJECT NO.: **09417-360-0230**

BPIP View - Lakes Environmental Software

J:\AQES\Projects\Steag Power\Class II 2001-2003\GEP\steag2.bpu

6.3.3 Sensitive Class II Areas

CALPUFF was used to assess impacts at distant sensitive Class II areas (beyond 50 kilometers) as requested by the Federal Land Managers (FLMs). These areas are shown in Figure 6-6, and include:

- Aztec Ruins National Monument
- Canyon de Chelly National Monument
- Chaco Culture National Historic Park
- Colorado National Monument
- Cruces Basin Wilderness Area
- Curecanti National Recreation Area
- El Malpais National Monument
- El Morro National Monument
- Glen Canyon National Recreation Area
- Hovenweep National Monument
- Hubbel Trading Post National Historic Site
- Lizard Head Wilderness Area
- Mount Sneffels Wilderness Area
- Natural Bridges National Monument
- Navajo National Monument
- Pecos National Historic Park
- Petroglyph National Monument
- Rainbow Bridge National Monument
- Salinas Pueblo Missions National Monument
- South San Juan Wilderness Area
- Sunset Crater National Monument
- Wupatki National Monument
- Yucca House National Monument
- Zuni-Cibola NHP
- Wilson Mountain Primitive Area
- Uncompahgre Wilderness Area

Figure 6-6 Distant Sensitive PSD Class II Areas Considered in the Modeling Analysis

Except where noted below, impacts at these areas have been addressed in terms of PSD Class II increment, regional haze, and acidic deposition. For all pollutants and averaging periods at each distant PSD Class I area, the modeling results discussed below show the project to have an insignificant modeled increment, so no further modeling is required (Class II significance thresholds are shown in Table 6-5). Since these areas are not Class I designated, regional haze and acidic deposition results associated with emissions from the main stacks alone are not subject to the FLAG Phase I (2000) procedures, and the results are being reported for informational purposes and are not being compared to thresholds that are applicable for a Class I area.

Colorado National Monument, Wilson Mountain Primitive Area, and Uncompahgre Wilderness Area are Class I protected areas for SO_2 PSD increment in Colorado. Therefore, the SO_2 Class I significance thresholds and increments will apply to these Class II areas only. Proposed Class I significance thresholds and increment values can be found in Table 6-5.

Table 6-5
Significant Impact Levels and PSD Increments

Pollutant	Averaging Period	Significant Impact Levels		PSD Increments	
		Class II [1] ($\mu g/m^3$)	Class I [2] ($\mu g/m^3$)	Class II ($\mu g/m^3$)	Class I ($\mu g/m^3$)
NO_2	Annual	1	0.1	25	2.5
SO_2	Annual	1	0.1	20	2
	24-hour	5	0.2	91	5
	3-hour	25	1	512	25
PM_{10}	Annual	1	0.2	17	4
	24-hour	5	0.3	30	8
CO	8-hour	500	N/A	N/A	N/A
	1-hour	2,000	N/A	N/A	N/A

1. Not to be exceeded
2. Proposed by EPA (1996; 61 FR 38249)
There are no SILs or PSD Increments for ozone or lead.

This modeling analysis assessed the impacts at the specified Class II areas from the proposed project's two main stacks alone operating at 100 percent load. Other small ancillary or fugitive sources were not included in this portion of the modeling analysis because the effects of these sources are expected to be confined within the first few kilometers of the project site.

Receptor grids for these areas were generated based on the suggestions of John Notar of the NPS. Receptor elevations were either picked from a topographic map or calculated using 90-meter spaced Digital Elevation Model (DEM) files.

6.3.4 Class II Modeling Results

Results of the near-field (within 55 km) PSD Class II increment modeling from proposed source emissions are provided in Tables 6-6a and 6-6b. The results indicate the following:

- The project emissions have a significant impact for NO_x, SO_2, and PM_{10}, and an insignificant impact for CO.
- The project impacts are below the PSD increments. Most of the peak air quality impacts are within 1 kilometer of the plant fenceline, so there is little likelihood for interaction with other sources in the area.
- The following Significant Impact Area distances resulted:
  - 9.0 km for NO_x,
  - 15.7 km for SO_2, and
  - 3.0 km for PM_{10}.
- The project has an insignificant impact for all pollutants modeled in areas outside the Navajo Nation, including the area to the north in the Ute Mountains.

Steag will work with the reviewing agencies to obtain a background emissions inventory for an area extending out 50 km beyond the respective SIA for NO_x, SO_2, and PM_{10}. Background monitored data reported in the modeling protocol will be added to the modeled NAAQS impacts to determine the total local air quality impact of the proposed facility. Steag anticipates that the result of the analysis will show that the proposed project does not cause or contribute to a violation of PSD Class II increments or the NAAQS.

Table 6-6a
Maximum Predicted Air Quality Impacts from the Proposed Project: Navajo Nation

Pollutant	Averaging Period	Maximum Modeled Conc. (μg/m³)	Distance (km)	Bearing (Deg.)	SIL (μg/m³)	% of SIL	PSD Class II Increment (μg/m³)	% of Incr.	NAAQS (μg/m³)	% of Ambient Standard
NO_X	Annual	4.9	0.7	105	1	489	25	20	100	5
SO_2	3 Hour	389.6	0.7	265	25	1558	512	76	1300	30
	24 Hour	39.1	0.7	265	5	781	91	43	365	11
	Annual	2.4	1.7	106	1	237	20	12	80	3
PM_{10}	24 Hour	15.1	0.7	265	5	303	30	50	150	10
	Annual	1.9	0.7	37	1	194	17	11	50	4
CO	1 Hour	1269.9	0.7	265	2000	63	N/A	N/A	40,000	3
	8 Hour[1]	431.1	0.7	265	500	86	N/A	N/A	10,000	4
Pb	Quarterly	0.12	0.7	265	N/A	N/A	N/A	N/A	1.5	8

1. CALPUFF does not provide 8-hour average results, so a conservatively high 3-hour average is provided for CO.

Table 6-6b
Maximum Predicted Air Quality Impacts from the Proposed Project: New Mexico

Pollutant	Averaging Period	Maximum Modeled Conc. (μg/m³)	Distance (km)	Bearing (Deg.)	SIL (μg/m³)	% of SIL	PSD Class II Increment (μg/m³)	% of Incr.	NAAQS (μg/m³)	% of Ambient Standard
NO_X	Annual	0.4	24.7	100	1	39	25	2	100	0.4
	24-hr[2]	3.4	24.7	10	N/A	N/A	N/A	N/A	N/A	N/A
SO_2	3 Hour	24.8	24.7	100	25	99	512	5	1,300	1.9
	24 Hour	2.7	24.7	100	5	54	91	3	365	0.7
	Annual	0.3	24.7	100	1	30	20	1	80	0.4
PM_{10}	24 Hour	0.9	24.7	100	5	18	30	3	150	0.6
	Annual	0.1	24.7	100	1	10	17	1	50	0.2
CO	1 Hour	45.9	24.7	90	2000	2	N/A	N/A	40,000	0.1
	8 Hour[1]	27.5	24.7	100	500	5	N/A	N/A	10,000	0.3
Pb	Quarterly	0.012	24.7	100	N/A	N/A	N/A	N/A	2	0.6

1. CALPUFF does not provide 8-hour average results, so a conservatively high 3-hour average is provided for CO.
2. A 24-hour state of New Mexico standard applies for receptors outside of the Navajo Nation.

The sensitive and/or protected PSD Class II areas noted by the Federal Land Managers are all beyond 50 km from the proposed source. Results of the PSD Class II increment modeling for these distant areas are provided in Table 6-7. For these Class II areas, there are no impacts above the Class II SILs. The three areas in Colorado where PSD Class I SO_2 increments apply are noted in the table, and the concentrations are above the Class I SILs in these three areas (bolded in yellow). For informational purposes, results of the visibility (regional haze) assessment for these areas are provided in Tables 6-8a and b, and of the sulfur and nitrogen deposition modeling are provided in Table 6-9.

Table 6-7
Highest Modeled PSD Increment Concentrations ($\mu g/m^3$)
Over Three Years (2001-2003), Distant Class II Areas

Pollutant	NO_X	SO_2			PM_{10}	
Averaging Period	Annual	3-hour	24-hour	Annual	24-hour	Annual
Aztec Ruins Nat. Mon.	0.021	4.385	0.628	0.050	0.426	0.045
Canyon de Chelly Nat. Mon.	0.009	3.549	0.462	0.019	0.589	0.019
Chaco Culture NHP	0.100	7.776	1.045	0.118	0.842	0.074
Colorado Nat. Mon.*	0.003	1.183	0.203	0.006	0.208	0.007
Cruces Basin NWA	0.011	1.876	0.236	0.019	0.212	0.020
Curecanti NRA	0.003	1.224	0.154	0.005	0.309	0.007
El Malpais Nat. Mon.	0.010	2.402	0.266	0.015	0.405	0.014
El Morro Nat. Mon.	0.005	2.086	0.209	0.009	0.212	0.010
Glen Canyon NRA	0.015	3.045	0.518	0.030	0.551	0.027
Hovenweep Nat. Mon.	0.006	1.754	0.305	0.022	0.347	0.022
Hubbel Trading Post NHS	0.002	1.037	0.198	0.007	0.388	0.009
Lizard Head NWA	0.005	1.649	0.249	0.011	0.360	0.012
Mount Sneffels NWA	0.004	1.311	0.199	0.008	0.372	0.011
Natural Bridges Nat. Mon.	0.009	2.221	0.382	0.017	0.399	0.017
Navajo Nat. Mon.	0.003	1.726	0.222	0.006	0.437	0.008
Pecos NHP	0.004	1.199	0.291	0.010	0.268	0.016
Petroglyph Nat. Mon.	0.022	1.874	0.470	0.032	0.367	0.027
Rainbow Bridge Nat. Mon.	0.001	1.087	0.230	0.005	0.381	0.008
Salinas Pueblo Missions Nat. Mon.	0.007	1.181	0.204	0.012	0.242	0.012
South San Juan NWA	0.014	2.849	0.368	0.022	0.267	0.021
Sunset Crater Nat. Mon.	0.000	0.692	0.111	0.002	0.232	0.004
Uncompahgre NWA*	0.007	1.376	0.317	0.011	0.360	0.012
Wilson Mountain Primitive Area*	0.004	1.465	0.209	0.010	0.327	0.012
Wupatki Nat. Mon.	0.000	0.322	0.120	0.002	0.252	0.004
Yucca House Nat. Mon.	0.008	2.150	0.326	0.018	0.363	0.018
Zuni-Cibola NHP	0.005	2.130	0.323	0.009	0.289	0.010
* subject under Colorado regulation to Class I SO_2 increment protection						

Table 6-8a
CALPUFF PSD Class II Regional Haze Impact Analysis (Highest Extinction Over Three Years), Distant PSD Class II Areas

Class II Area	Max Percent (%) Extinction Change
Aztec Ruins Nat. Mon.	12.61
Canyon de Chelly Nat. Mon.	12.06
Chaco Culture NHP	35.62
Colorado Nat. Mon.	5.92
Cruces Basin NWA	11.26
Curecanti NRA	10.05
El Malpais Nat. Mon.	11.34
El Morro Nat. Mon.	10.67
Glen Canyon NRA	15.46
Hovenweep Nat. Mon.	14.14
Hubbel Trading Post NHS	11.08
Lizard Head NWA	26.27
Mount Sneffels NWA	12.35
Natural Bridges Nat. Mon.	11.11
Navajo Nat. Mon.	17.55
Pecos NHP	7.66
Petroglyph Nat. Mon.	8.31
Rainbow Bridge Nat. Mon.	7.25
Salinas Pueblo Missions Nat. Mon.	4.61
South San Juan NWA	14.06
Sunset Crater Nat. Mon.	5.46
Uncompahgre NWA	14.24
Wilson Mountain Primitive Area	10.93
Wupatki Nat. Mon.	5.90
Yucca House Nat. Mon.	14.98
Zuni-Cibola NHP	12.00
FLAG f(RH) Values, MVISBK=2, RHMAX=95%, 10% ranked lowest background extinction	

Results in Table 6-8a employ the FLAG f(RH) curve, while the values in Table 6-8b employ the recently published EPA updates to the f(RH) curve. The EPA version of the f(RH) curve generally results in lower predicted changes to regional haze impacts. The 10% ranked lowest background extinction values are obtained from data provided prior to FLAG implementation by John Notar of the National Park Service to Robert Paine of ENSR. No attempt has been made to refine these results by reviewing periods of natural obscuration due to meteorological interferences. Steag provides this information to show that the proposed project will not have an adverse impact on distant PSD Class II areas.

Table 6-8b
CALPUFF PSD Class II Regional Haze Impact Analysis (Highest Extinction Over Three Years), Distant PSD Class II Areas

Class II Area	Max Percent (%) Extinction Change
Aztec Ruins Nat. Mon.	10.95
Canyon de Chelly Nat. Mon.	11.47
Chaco Culture NHP	30.30
Colorado Nat. Mon.	5.67
Cruces Basin NWA	9.72
Curecanti NRA	10.64
El Malpais Nat. Mon.	11.03
El Morro Nat. Mon.	9.55
Glen Canyon NRA	15.50
Hovenweep Nat. Mon.	13.07
Hubbel Trading Post NHS	10.91
Lizard Head NWA	22.56
Mount Sneffels NWA	13.21
Natural Bridges Nat. Mon.	11.21
Navajo Nat. Mon.	15.48
Pecos NHP	6.81
Petroglyph Nat. Mon.	8.76
Rainbow Bridge Nat. Mon.	7.84
Salinas Pueblo Missions Nat. Mon.	5.02
South San Juan NWA	11.59
Sunset Crater Nat. Mon.	6.05
Uncompahgre NWA	14.34
Wilson Mountain Primitive Area	11.72
Wupatki Nat. Mon.	6.53
Yucca House Nat. Mon.	13.73
Zuni-Cibola NHP	10.84
EPA f(RH) Values, MVISBK=2, RHMAX=95%, 10% ranked lowest background extinction	

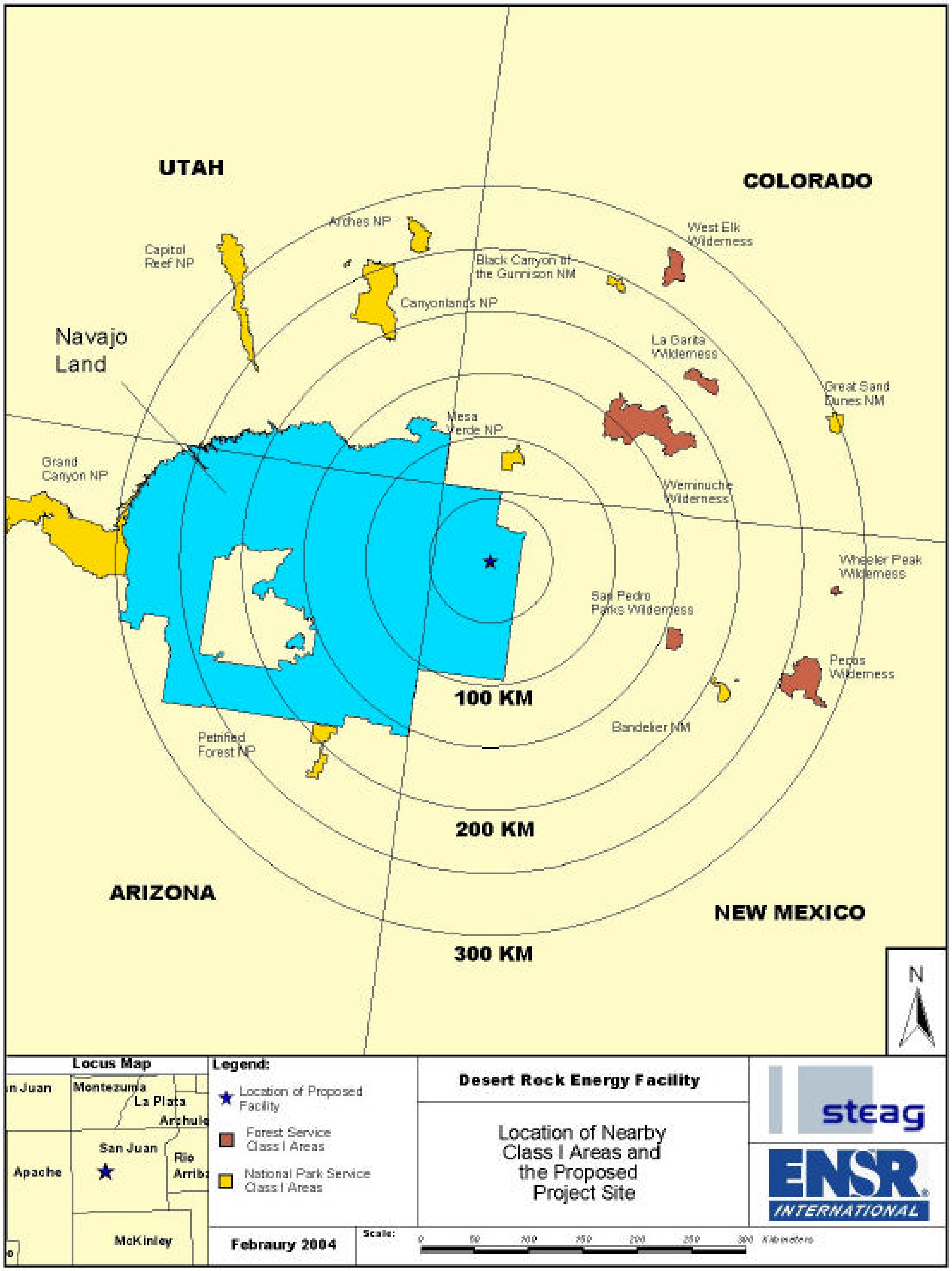
Table 6-9
Maximum Total Deposition Over Three Years (2001-2003), Distant PSD Class II Areas

PSD Class II Area	Nitrogen Deposition (kg/ha/yr)	Sulfur Deposition (kg/ha/yr)
Aztec Ruins Nat. Mon.	1.42E-02	4.35E-02
Canyon de Chelly Nat. Mon.	6.60E-03	1.54E-02
Chaco Culture NHP	2.56E-02	5.03E-02
Colorado Nat. Mon.	1.91E-03	4.29E-03
Cruces Basin NWA	6.47E-03	1.39E-02
Curecanti NRA	2.50E-03	5.24E-03
El Malpais Nat. Mon.	4.35E-03	9.05E-03
El Morro Nat. Mon.	2.84E-03	5.90E-03
Glen Canyon NRA	5.12E-03	1.28E-02
Hovenweep Nat. Mon.	6.08E-03	1.59E-02
Hubbel Trading Post NHS	3.01E-03	6.53E-03
Lizard Head NWA	4.59E-03	1.03E-02
Mount Sneffels NWA	3.37E-03	7.63E-03
Natural Bridges Nat. Mon.	5.08E-03	1.19E-02
Navajo Nat. Mon.	2.02E-03	4.82E-03
Pecos NHP	4.02E-03	9.60E-03
Petroglyph Nat. Mon.	6.72E-03	1.47E-02
Rainbow Bridge Nat. Mon.	1.32E-03	3.71E-03
Salinas Pueblo Missions Nat. Mon.	2.92E-03	6.21E-03
South San Juan NWA	8.38E-03	1.77E-02
Sunset Crater Nat. Mon.	9.35E-04	1.91E-03
Uncompahgre NWA	4.05E-03	8.32E-03
Wilson Mountain Primitive Area	3.81E-03	8.81E-03
Wupatki Nat. Mon.	9.29E-04	1.90E-03
Yucca House Nat. Mon.	6.25E-03	1.70E-02
Zuni-Cibola NHP	3.46E-03	7.06E-03

6.4 PSD Class I Modeling Analysis

The impacts at PSD Class I areas within 300 kilometers of the proposed plant (see Figure 6-7) were modeled with CALPUFF. The PSD Class I areas included the following National Parks: Arches, Bandelier, Black Canyon of the Gunnison, Capitol Reef, Canyonlands, Grand Canyon, Great Sand

Figure 6-7 PSD Class I Areas Considered in the Modeling Analysis



Dunes, Mesa Verde, and Petrified Forest. Also included were La Garita, Pecos, San Pedro Parks, West Elk, Weminuche, and Wheeler Peak Wilderness Areas, all administered by the USDA Forest Service. The long-range analysis will address ambient air impacts on Class I PSD Increments and Air Quality Related Values (AQRVs) at these Class I areas.

6.4.1 Modeling Domain and Receptors

The CALPUFF modeling grid system was designed to extend approximately 50 kilometers east of Great Sand Dunes National Park, north of West Elk Wilderness, south of Petrified Forest, as well as 350 kilometers west of the project site. The modeling domain proposed for this analysis is shown in Figure 6-8. The additional buffer distances beyond the Class I areas allow for the consideration of puff trajectory recirculations. This design allows for a 680 km x 552 km (E-W / N-S) grid with a 4-km grid element size. The southwest corner of the grid is located at approximately 34.28° N latitude and 112.46° W longitude.

The receptors used in the refined CALPUFF analysis were limited to those actually within the PSD Class I boundary. However, if the park boundary extended more than 300 kilometers from the project site, then only those receptors within 300 kilometers were modeled in this CALPUFF analysis. The receptors for Arches, Bandelier, Black Canyon of the Gunnison, Capitol Reef, Canyonlands, Grand Canyon, Great Sand Dunes, Mesa Verde, and Petrified Forest National Parks, along with La Garita, Pecos, San Pedro Parks, West Elk, Weminuche, and Wheeler Peak Wilderness Areas were obtained from a database of receptors for all Class I areas produced by the National Park Service.

6.4.2 Increment Consumption Modeling Results

Results of the PSD Class I increment modeling from proposed source emissions are provided in Table 6-10. Values bolded in yellow are greater than the Class I significance levels. The NO_x impacts are insignificant in all PSD Class I areas. The SO_2 and PM_{10} impacts are significant. Note that the highest SO_2 impacts are slightly above 20% of the full PSD Class I increment and the highest PM_{10} impacts are slightly above 10% of the full PSD Class I increment. Therefore, there is a good possibility that a cumulative analysis will show that the PSD increments are within compliance.

6.4.3 Regional Haze Impacts

Results of the regional haze impacts from the proposed source are provided in Tables 6-11a through 6-11f. The results are presented in terms of the change in light extinction from natural background extinction as provided in the FLAG (2000) guidance. These results are supplemented by several refinements in the regional haze impacts, as follows:

- A relative humidity cap of 95% is considered, with other FLAG procedures unchanged.
- The f(RH) curves adopted by EPA (2003) are used.

Figure 6-8 PSD Class I CALPUFF Modeling Domain

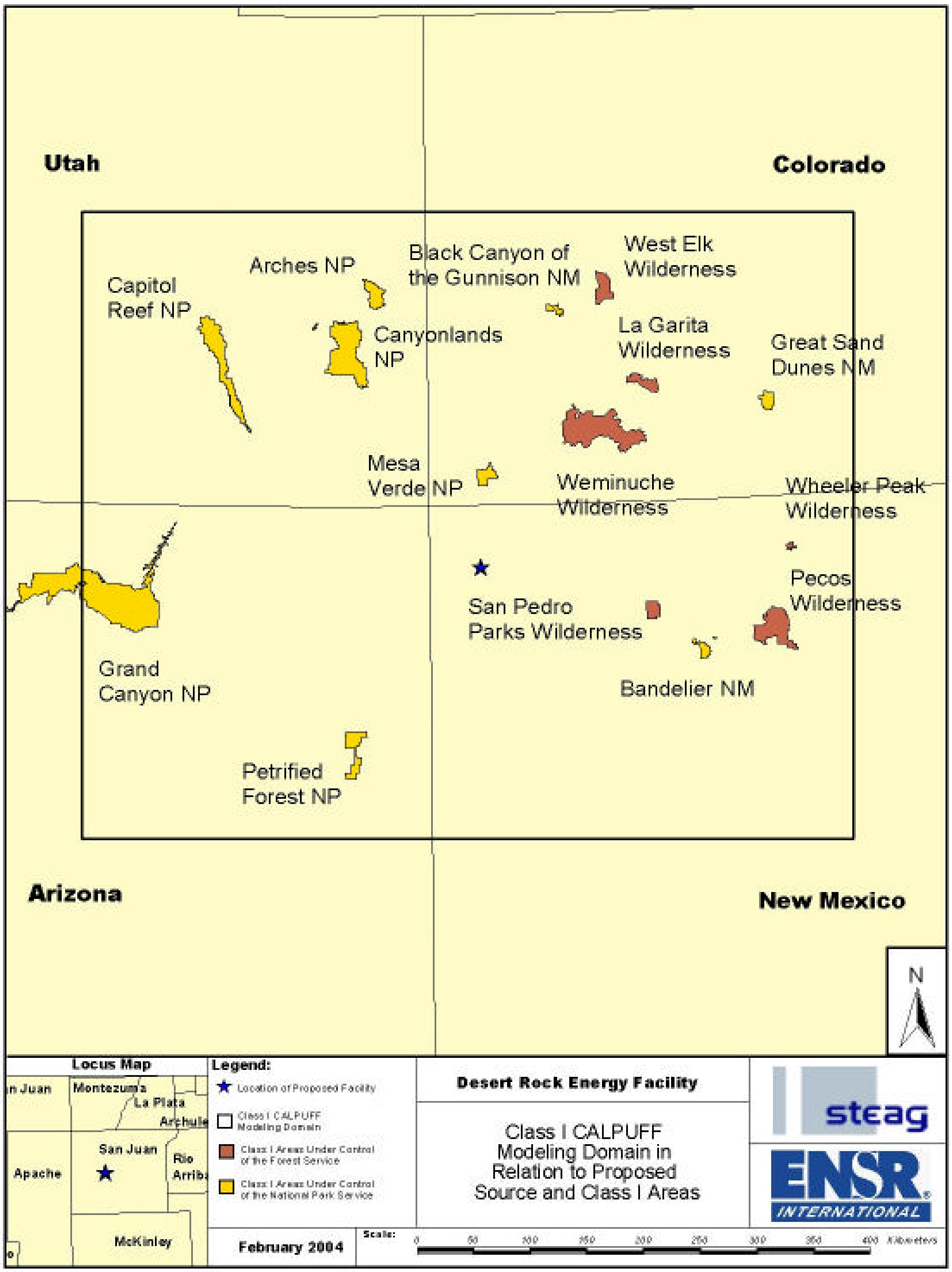


Table 6-10
Highest Modeled PSD Increment Concentrations (µg/m^3) Over Three Years (2001-2003)

Pollutant	**NO_X**	**SO_2**			**PM_{10}**	
Averaging Period	**Annual**	**3-hour**	**24-hour**	**Annual**	**24-hour**	**Annual**
Arches NP	0.002	1.113	0.144	0.006	0.220	0.008
Bandelier NM	0.013	1.817	0.300	0.022	0.289	0.026
Black Canyon of the Gunnison NM	0.003	1.246	0.168	0.006	0.308	0.008
Canyonlands NP	0.006	2.364	0.465	0.010	0.393	0.011
Capitol Reef NP	0.003	1.488	0.293	0.008	0.333	0.010
Grand Canyon NP	0.000	0.556	0.181	0.002	0.249	0.005
Great Sand Dunes NM	0.007	1.575	0.299	0.013	0.355	0.015
La Garita Wilderness	0.007	1.516	0.273	0.012	0.300	0.013
Mesa Verde NP	0.025	5.859	1.055	0.037	0.536	0.029
Pecos Wilderness	0.008	1.912	0.277	0.014	0.225	0.018
Petrified Forest NP	0.001	0.766	0.186	0.004	0.499	0.006
San Pedro Parks Wilderness	0.026	3.479	0.621	0.037	0.408	0.038
Weminuche Wilderness	0.012	2.756	0.312	0.019	0.322	0.018
West Elk Wilderness	0.002	0.746	0.108	0.005	0.255	0.007
Wheeler Peak Wilderness	0.006	1.410	0.160	0.011	0.220	0.014
SIL	0.1	1.0	0.2	0.1	0.3	0.2
PSD Increments	2.5	25.0	5.0	2.0	8.0	4.0

- The contribution to natural background extinction by airborne salt particles, which are ignored by FLAG, is considered. Although the area in question is removed from the Pacific Ocean, there are plentiful sources of salt aerosols in the West from surface salt deposits and flats, as well as salt lakes. The general procedures used in the determination of the salt concentration (a hygroscopic particulate component), are described in Appendix F of Attachment 1 (Modeling Protocol). The concentrations of airborne salt particles were obtained from IMPROVE measurements available at most of the PSD Class I areas, and are listed in Table 6-12.
- The alternative use of monthly relative humidity values (CALPOST option MVISBK = 6) is employed to eliminate computations with very high hourly relative humidity values, which are likely to be associated with natural meteorological interference periods.
- The alternative use of CALPOST option MVISBK = 3, combined with a relative humidity cap of 89.9%, is employed to eliminate from consideration hours with relative humidities of 90% or more, which are likely to be associated with natural meteorological interference periods.

The regional haze modeling results in Tables 6-11d through f (which incorporate reasonable and technically defensible refinements to FLAG) indicate that there are relatively few days with modeled visibility extinction changes above 10% of natural background. A quick review of the weather conditions on these days indicates that virtually all of them can be documented as being associated with one or more of the following natural interferences to visibility:

- Occurrences of rain, snow, fog, etc.;
- Reduced visibility measurements at nearby representative airports;
- Cloud cover and/or elevated relative humidity at night, which would tend to preclude star-gazing activities.
- It is anticipated that a cumulative regional haze analysis has a strong possibility of showing that all days with modeled extinction changes over 10% (with the use of refinements used in the Table 6-11d results) are associated with natural obscuration, and that the proposed project should not cause an adverse visibility impact in any PSD Class I area.

Table 6-11a
Regional Haze Analysis #1

Class I Area	Worst-Case Year	No. of Days Over 5%	No. of Days Over 10%	Max % Change
Arches NP	2001	4	0	8.69
Bandelier NM	2001	7	2	23.00
Black Canyon of the Gunnison NM	2001	1	1	10.24
Canyonlands NP	2003	4	1	31.23
Capitol Reef NP	2002	2	1	11.04
Grand Canyon NP	2002	1	1	16.85
Great Sand Dunes NM	2002	6	1	13.55
La Garita WA	2001	2	1	14.68
Mesa Verde NP	2002	19	4	42.87
Pecos WA	2001	7	2	17.91
Petrified Forest NP	2002	6	2	27.60
San Pedro Parks WA	2001	15	5	42.39
Weminuche WA	2001	22	6	21.10
West Elk WA	2001	2	1	12.65
Wheeler Peak WA	2003	1	1	10.18
Worst-case year: FLAG f(RH) Values, MVISBK=2, RHMAX=98%				

Table 6-11b
Regional Haze Analysis #2

Class I Area	Worst-Case Year	No. of Days Over 5%	No. of Days Over 10%	Max % Change
Arches NP	2001	3	0	7.65
Bandelier NM	2001	7	2	18.06
Black Canyon of the Gunnison NM	2001	1	1	10.24
Canyonlands NP	2003	4	1	26.04
Capitol Reef NP	2002	2	0	8.90
Grand Canyon NP	2002	1	1	14.66
Great Sand Dunes NM	2002	6	1	13.55
La Garita WA	2001	2	1	12.78
Mesa Verde NP	2002	18	4	34.11
Pecos WA	2001	6	1	13.79
Petrified Forest NP	2002	5	2	26.62
San Pedro Parks WA	2001	11	4	33.03
Weminuche WA	2001	16	4	14.29
West Elk WA	2001	2	1	11.43
Wheeler Peak WA	2002	1	0	8.86
Worst-case year: FLAG f(RH) Values, MVISBK=2, RHMAX=95%				

Table 6-11c
Regional Haze Analysis #3

Class I Area	Worst-Case Year	No. of Days Over 5%	No. of Days Over 10%	Max % Change
Arches NP	2001	3	0	7.68
Bandelier NM	2001	6	2	15.54
Black Canyon of the Gunnison NM	2001	1	1	10.85
Canyonlands NP	2003	7	1	21.13
Capitol Reef NP	2003	6	0	8.78
Grand Canyon NP	2002	1	1	13.74
Great Sand Dunes NM	2002	5	1	13.77
La Garita WA	2001	2	1	12.68
Mesa Verde NP	2002	18	2	29.75
Pecos WA	2001	4	1	11.91
Petrified Forest NP	2002	5	1	24.28
San Pedro Parks WA	2001	11	4	28.22
Weminuche WA	2001	16	2	13.32
West Elk WA	2001	2	1	11.59
Wheeler Peak WA	2002	1	0	9.14
Worst-case year: EPA f(RH) Values, MVISBK=2, RHMAX=95%				

Table 6-11d
Regional Haze Analysis #4

Class I Area	Worst-Case Year	No. of Days Over 5%	No. of Days Over 10%	Max % Change
Arches NP	2001	3	0	7.49
Bandelier NM	2001	6	2	14.59
Black Canyon of the Gunnison NM	2001	1	1	10.48
Canyonlands NP	2003	5	1	19.53
Capitol Reef NP	2003	5	0	8.28
Grand Canyon NP	2002	1	1	12.79
Great Sand Dunes NM	2002	5	1	13.21
La Garita WA	2001	2	1	12.09
Mesa Verde NP	2002	17	2	27.32
Pecos WA	2001	3	1	11.18
Petrified Forest NP	2002	5	1	22.40
San Pedro Parks WA	2001	10	4	26.17
Weminuche WA	2001	12	2	12.75
West Elk WA	2001	1	1	11.05
Wheeler Peak WA	2002	1	0	8.68
Worst-case year: EPA f(RH) Values, MVISBK=2, RHMAX=95%, Includes Salt Aerosol				

Table 6-11e
Regional Haze Analysis #5

Class I Area	Worst-Case Year	No. of Days Over 5%	No. of Days Over 10%	Max % Change
Arches NP	2001	2	0	7.49
Bandelier NM	2003	5	1	11.54
Black Canyon of the Gunnison NM	2001	1	1	10.48
Canyonlands NP	2001	2	1	14.28
Capitol Reef NP	2003	5	1	10.09
Grand Canyon NP	2002	1	1	10.42
Great Sand Dunes NM	2002	5	1	13.21
La Garita WA	2001	1	1	11.04
Mesa Verde NP	2002	16	1	14.89
Pecos WA	2001	4	0	8.51
Petrified Forest NP	2002	4	2	18.36
San Pedro Parks WA	2001	7	2	12.87
Weminuche WA	2001	7	1	12.53
West Elk WA	2001	1	1	10.74
Wheeler Peak WA	2002	1	0	8.68
Worst-case year: EPA f(RH) Values, MVISBK=3, RHMAX=89.9%, Includes Salt Aerosol				

Table 6-11f
Regional Haze Analysis #6

Class I Area	Worst-Case Year	No. of Days Over 5%	No. of Days Over 10%	Max % Change
Arches NP	2001	3	0	8.50
Bandelier NM	2002	5	0	9.87
Black Canyon of the Gunnison NM	2001	1	1	11.75
Canyonlands NP	2001	4	1	13.88
Capitol Reef NP	2003	6	1	10.78
Grand Canyon NP	2002	1	0	8.81
Great Sand Dunes NM	2002	5	1	11.93
La Garita WA	2001	1	1	10.44
Mesa Verde NP	2002	16	2	18.08
Pecos WA	2002	4	0	7.19
Petrified Forest NP	2002	3	1	16.89
San Pedro Parks WA	2001	10	1	15.11
Weminuche WA	2001	6	1	12.28
West Elk WA	2001	1	0	8.89
Wheeler Peak WA	2002	2	0	8.06
Worst-case year: EPA f(RH) Values, MVISBK=6, Monthly RHFAC, Includes Salt Aerosol				

Table 6-12
Annual Average Sea Salt Concentrations in PSD Class I Areas (from IMPROVE Data)

PSD Class I Area	Annual Average NaCl Conc. (µg/m³)
Arches NP	0.065
Bandelier NM	0.095
Black Canyon of the Gunnison NM[1]	0.086
Canyonlands NP	0.113
Capitol Reef NP	0.098
Grand Canyon NP – Hance	0.117
Great Sand Dunes NM	0.099
La Garita WA[1]	0.086
Mesa Verde NP	0.117
Pecos WA [2]	0.095
Petrified Forest NP	0.150
San Pedro Parks WA	0.114
Weminuche WA	0.086
West Elk WA [1]	0.086
Wheeler Peak WA	0.100

1. Used data from Weminuche WA
2. Used data from Bandelier NM

6.4.4 Sulfur and Nitrogen Deposition Analysis

Results of the sulfur and nitrogen deposition analysis due to emissions from the proposed source are provided in Tables 6-13 and 6-14. There are no published thresholds for acidic deposition for the PSD Class I areas in which acidic deposition impacts will be addressed. The deposition results are provided here for evaluation by the FLMs. However, it is noted that the United States Department of Agriculture Forest Service web site (http://www.fs.fed.us/r6/aq/natarm/document.htm) indicates that the minimum detectable level for measuring an increase in wet deposition of sulfates or nitrates is 0.5 kg/ha/yr. For conservatism, the Forest Service recommends a significance level of one tenth of this minimum detectable level, or 0.05 kg/ha/yr. The FLM has also recently developed a Deposition Analysis Threshold (DAT) for nitrogen of 0.005 kg/ha/yr (FLAG, 2001) to be used as a trigger for further FLM analysis, rather than as an adverse impact threshold (Porter, 2004). Values shaded in Tables 6-13 and 6-14 are above the DAT levels.

Table 6-13
Maximum Total Nitrogen Deposition Over Three Years (2001-2003)

PSD Class I Area	Nitrogen Deposition (kg/ha/yr)	Screening Threshold Value (kg/ha/yr)
Arches NP	1.97E-03	5.00E-03
Bandelier NM	7.89E-03	5.00E-03
Black Canyon of the Gunnison NM	2.35E-03	5.00E-03
Canyonlands NP	3.22E-03	5.00E-03
Capitol Reef NP	1.49E-03	5.00E-03
Grand Canyon NP	7.01E-04	5.00E-03
Great Sand Dunes NM	3.21E-03	5.00E-03
La Garita WA	4.64E-03	5.00E-03
Mesa Verde NP	1.34E-02	5.00E-03
Pecos WA	5.05E-03	5.00E-03
Petrified Forest NP	2.04E-03	5.00E-03
San Pedro Parks WA	1.17E-02	5.00E-03
Weminuche WA	9.21E-03	5.00E-03
West Elk WA	1.99E-03	5.00E-03
Wheeler Peak WA	4.25E-03	5.00E-03

Table 6-14
Maximum Total Sulfur Deposition Over Three Years (2001-2003)

PSD Class I Area	Sulfur Deposition (kg/ha/yr)	Screening Threshold Value (kg/ha/yr)
Arches NP	2.90E-03	5.00E-03
Bandelier NM	1.58E-02	5.00E-03
Black Canyon of the Gunnison NM	4.64E-03	5.00E-03
Canyonlands NP	6.05E-03	5.00E-03
Capitol Reef NP	1.40E-03	5.00E-03
Grand Canyon NP	8.07E-04	5.00E-03
Great Sand Dunes NM	6.87E-03	5.00E-03
La Garita WA	9.50E-03	5.00E-03
Mesa Verde NP	3.07E-02	5.00E-03
Pecos WA	1.03E-02	5.00E-03
Petrified Forest NP	1.35E-03	5.00E-03
San Pedro Parks WA	2.40E-02	5.00E-03
Weminuche WA	1.84E-02	5.00E-03
West Elk WA	4.23E-03	5.00E-03
Wheeler Peak WA	7.91E-03	5.00E-03

6.5 Growth Analysis

A growth analysis examines the potential emissions from secondary sources associated with the proposed project. While these activities are not directly involved in project operation, the emissions can reasonably be expected to occur. For the proposed Desert Rock Energy Facility, secondary emissions will be associated with:

- coal processing and handling activities associated with the coal supply, and
- the project workforce.

The secondary emissions associated with the Project are not expected to be substantial when compared to direct emissions during either construction or operation of the facility. As discussed below, the emissions associated with the coal supply system will occur during plant operation and will be primarily due to road dust from coal haul truck operation on unpaved roads. There will be little new growth in the area due to the small work force (200-225 employees) expected during plant operation. The emissions associated with the workforce will be primarily the result of motor vehicle exhaust emissions associated with the commute of workers to and from the plant site.

The emissions associated with the coal operation are expected to be localized in the immediate area of the mine and power plant. The emissions due to worker commute are expected to be distributed over a two-county area of San Juan and McKinley counties with limited impact at any given location. Based on this analysis, we conclude that there will be little impact beyond the local area surrounding the Desert Rock Energy Facility due to secondary emission sources.

6.5.1 Secondary Emissions Associated with Coal Supply

Coal for the Desert Rock Energy Facility will be purchased under a contract with BHP, the operators of the Navajo Mine. The design specifications for the coal will require BHP to blend coal from up to five of the Navajo Mine coal seams.

Coal will be mined from an open pit and transported to the crushing plant by off-road mining trucks. The run-of-mine coal will be crushed and blended to meet the design specification of the proposed facility. The blended coal will be fed onto a conveyor and transported to the coal bunkers of the proposed facility.

The coal handling facility will store approximately a 30-day supply of blended coal on site as a strategic reserve. For normal operations of the facility this coal will remain untouched. The mine will also maintain, on their site, a coal storage area with run-off-mine coal equal to a 30-day supply at full load operation. Furthermore behind the crushing plant within the area of the mine, another coal storage area for blended/crushed coal will be built. Under normal operating conditions the power plant will be supplied with coal directly from this coal pile. The capacity of the storage pile is enough to run the unit under full load for 7 days.

These coal preparation activities will likely be conducted in an area south of the current mining operations and east of the proposed power generation facility. The mining, storage and blending activities associated with providing coal for the facility are secondary activities caused by the plant operation.

BHP has not provided details on how they will supply the coal to Steag. Based on typical operations of this sort, the fugitive PM_{10} emissions associated with the coal supply system are expected to be on the order of 15 tpy from the coal handling activities and about 66 tpy from travel on unpaved roads to haul coal from the mine site to the crushing plant. These emissions will be controlled by use of water and/or surfactant sprays on haul roads and other industry-standard fugitive dust control measures. These fugitive dust emissions will be very localized to the mine and blending facility area. The emissions will be associated with non-buoyant plumes released from ground level or near-ground activities. The dust released is unlikely to travel significant distances. Given the rural location for the plant site and the limited transport distances expected of the fugitive PM_{10} emissions, the impact is expected to be minor from these secondary fugitive emissions associated with the coal supply operation.

6.5.2 Emissions Due to Workforce Travel

The Desert Rock Energy Facility is proposing to locate in San Juan County, New Mexico. During construction, the project is expected to employ about 800 workers, although the workforce may be up to 3,000 workers during peak construction periods. After start of operations, there will be approximately 200-225 employees.

The workers for the plant (both construction and operations) are primarily expected to come from San Juan County and adjoining McKinley County. It is expected that approximately 10% of the workforce will come from rural areas within the Navajo Nation. Most workers (~60%) will commute approximately 30 miles from the Farmington and Shiprock areas (San Juan County) while the remainder will commute approximately 75 miles from Gallup (McKinley County) and Window Rock (Apache County, Arizona). The Navajo Nation requires preferred employment of local people, hence many of the workers are expected to come from rural areas in the Navajo Nation.

The estimated 2002 population of San Juan and McKinley counties was 120,400 and 74,000 persons. The basic construction workforce of 800 persons is less than 0.4% of the population from which the labor pool will be drawn. Over the past six years, San Juan and McKinley Counties have consistently had unemployment above the statewide average. From published New Mexico Department of Labor statistics, the unemployment rate in San Juan and McKinley Counties in 2002 was 6.7% (3,500 persons) and 6.1% (1,600 persons), respectively, compared with the statewide total of 5.4%. While only a portion of the unemployed persons in the two counties would be qualified for construction or operation jobs at the plant, the number of unemployed workers in the two counties in 2002 is slightly less than two times the 3,000 workers on site during the peak periods and more than 6 times the daily average of 800 workers during most of the construction period. As many of the construction workers during peak periods will be transient workers hired or brought in by subcontractors, they may cause local short-term demand for services in area hotels and restaurants but will not contribute to permanent growth in the area due to their transient nature. Negligible growth is expected for the operation phase given the small number of operational workers (225) in a two-county region of nearly 200,000 persons.

Based on current unemployment levels, the requirement by the Navajo Nation for preferred employment for local persons, and the expectation that a significant number of workers will come from the existing employment pool in the area, population growth associated with the proposed project is expected to be small.

Consequently, secondary emission increases associated with the project workforce will be due primarily to worker commuter trips. As approximately 30% of the workers will commute from Gallup (approximately 75 miles) and 60% from Shiprock and Farmington (approximately 25 miles), an average commute on the order of 40 miles is a reasonable estimate. For construction, assuming 800 employee commute trips per day of 40 miles each way, the typical daily commute vehicle miles traveled (VMT) will be approximately 64,000 vehicle-miles per day. PM_{10}, VOC and NO_x from this traffic might be on the order of 15 tpy for the three-year construction period. For operations, the VMT will be much lower, less than approximately 18,000 vehicle-miles per day, or about 5 tpy of PM_{10}, VOC and NO_x.

Given the rural nature of the two-county region, vehicle emissions associated with the project workforce travel will likely be spread out over a substantial part of the two-county area, an area of over 8,500 square miles. Consequently, the impacts of any emissions will not be concentrated but rather will be dispersed throughout a large area, thus limiting local impacts in the largely rural counties.

6.6 Impacts on Soils and Vegetation

PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, and sensitive types of soil. Evaluation of impacts on sensitive vegetation were performed by comparing the predicted impacts attributable to the Project with the screening levels presented in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (EPA 1980); see Table 6-15.

Most of the designated vegetation screening levels are equivalent to or less stringent than the NAAQS and/or PSD increments, therefore satisfaction of NAAQS and PSD increments assures compliance with sensitive vegetation screening levels.

Table 6-15
Screening Concentrations for Soils and Vegetation

Pollutant	Averaging Period	Screening Concentration ($\mu g/m^3$)	Predicted Concentration ($\mu g/m^3$)
SO_2	1-Hour	917	1142.7
	3-Hour	786	389.6
	Annual	18	2.4
NO_2	4-Hours [1]	3,760	345.5
	1-Month [2]	564	103.8
	Annual	94	4.9
CO	Weekly [1]	1,800,000	431.1

Source: "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals". EPA 450/2-81-078, December 1980

1. Modeled with the 3-hour Averaging Time
2. Modeled with the 24-hour Averaging Time

6.7 Endangered Species and National Historic Preservation Acts

The proposed project requires Federal permits and an agreement to use lands of the Navajo Nation. As a result, the project requires review under and compliance with the National Environmental Policy Act (NEPA) (42 U.S.C. 4321-4347) and its implementing regulations. Under NEPA, the protection of environmental resources will be assessed and the potential impacts of the Project will be determined. This work will include a review under the Endangered Species Act (ESA) (7 U.S.C. 136; 16 U.S.C. 460 et seq.) and Section 106 of the National Historic Preservation Act (NHPA) and its implementing regulations (Protection of Historic Properties, 36 CFR 800). Steag is prepared to work with the Bureau of Indian Affairs (BIA), as the lead Federal agency under NEPA, in complying with all applicable regulations. A discussion of the project reviews to date under the ESA is contained in Attachment 5 and work related to the NHPA is contained in Attachment 6 of this application.

6.8 Summary of Air Quality Modeling Results

Dispersion modeling of the air quality impacts of the proposed Desert Rock Energy Facility has been completed. The results are summarized below.

6.8.1 PSD Class II results

- The project impacts are above PSD Class II significance levels for a limited area around the facility (about 8 km for NO_x, 15 km for SO_2, and 4 km for PM_{10}). The project has insignificant impacts for CO.
- The peak impacts from the facility are located very close to the plant fenceline (within 1 km in most cases). These impacts are likely due to emergency generators or auxiliary boilers that do not run continuously, although they were conservatively modeled to operation 8,760 hours per year.
- The PSD increment consumption due to the plant emissions are well within PSD Class II increments. Due to the lack of nearby combustion sources, it is likely that a cumulative modeling analysis would show compliance with PSD increments and the NAAQS.
- There are no modeled significant impacts from the proposed project in areas beyond the Navajo Nation, including New Mexico lands and the Ute Mountain range to the north.
- Impacts on numerous distant PSD Class II areas (located beyond 50 km) show increment consumption below significance limits. Steag has provided regional haze and deposition results for informational purposes, since PSD Class I limits are not applicable in Class II areas. No further modeling analysis for these distant areas is needed.
- Steag concludes that the project will have no adverse impacts in PSD Class II areas, upon the completion of a cumulative modeling analysis (to be discussed with EPA Region 9) to address impacts within the limited areas near the plant, as noted above.

6.8.2 PSD Class I Results

- The project impacts are above PSD Class I significance levels for SO_2 and PM_{10} in a number of areas (including three PSD Class II areas that have special Colorado designation as Class I for SO_2). The project has an insignificant impact for NO_2 increment.

- The project's impact is a small fraction of the total increment (slightly over 20% for SO_2 and 10% for PM_{10}). Due to increment expansion at the Four Corners Power Plant, Steag expects that a cumulative analysis will demonstrate that the project does not cause or contribute to a PSD Class I increment violation.

- The project's impacts on sulfur and nitrogen deposition are higher than the very low DAT levels that trigger additional review. The United States Department of Agriculture Forest Service web site (http://www.fs.fed.us/r6/aq/natarm/document.htm) indicates that the minimum detectable level for measuring an increase in wet deposition of sulfates or nitrates is 0.5 kg/ha/yr. For conservatism in judging impacts, the Forest Service recommends a deposition significance level of one tenth of this minimum detectable level, or 0.05 kg/ha/yr. All of the impacts modeled for the proposed plant are below this significance level, and include a component of ammonia salts that are not acidic. Steag therefore concludes that the proposed project does not adversely impact deposition. This information is being provided to the FLMs for their review.

- The project's impacts on regional haze are higher than insignificance thresholds of 5% change to background extinction. A number of refinements to FLAG are presented, and the results show that there are very few days over the three years modeled that exceed the cumulative threshold of a 10% change. A quick review of those days indicates that they can be documented as being associated with one or more of the following natural interferences to visibility:

  - Occurrences of rain, snow, fog, etc.;
  - Reduced visibility measurements at nearby representative airports;
  - Cloud cover and/or elevated relative humidity at night, which would tend to preclude star-gazing activities.

  It is therefore anticipated that a cumulative regional haze analysis has a strong possibility of showing that all days with modeled extinction changes over 10% (with the use of refinements used in the Table 6-11d results) are associated with natural obscuration, and that the proposed project should not cause an adverse visibility impact in any PSD Class I area.

6.8.3 Overall Conclusions

Based upon these findings, Steag concludes that the reviewing agencies have sufficient information in this permit application to evaluate the proposed project. Steag will work with the reviewing agencies to recommend a cumulative analysis that Steag expects will show that the project does not cause or contribute to a violation of an air quality standard, and does not adversely affect Air Quality Related Values in sensitive areas within several hundred kilometers from the proposed project site.

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