BASIN ELECTRIC
POWER COOPERATIVE

1717 EAST INTERSTATE AVENUE
BISMARCK, NORTH DAKOTA 58503-0564
PHONE 701-223-0441
FAX: 701/224-5336

NOV 2005

November 10, 2005

Mr. Bernie Dailey, PE
New Source Review Program Manager
Wyoming Department of Environmental Quality
Air Quality Division
Herschler Building, 4-W
122 West 25th Street
Cheyenne, WY 82002

RE: Application for Permit to Construct Dry Fork Station Project

Dear Mr. Dailey:

Enclosed are five (5) copies of the air quality construction permit application for the Dry Fork Station Project. The proposed unit will be a 422 MW (gross) coal-fired power generating unit constructed northeast of Gillette.

The enclosed documents contain all of the information that the Air Quality Division will need to review this application. Included in the application document are detailed descriptions of the proposed project, its related emissions, an analysis of applicable regulations, BACT analyses of the emissions controls, and near-field (ISC) and far-field (CALPUFF) modeling of the project impacts to evaluate its impact on air quality standards and air quality related values. Also included with this submittal are two (2) copies of the DVDs that contain all of the modeling input and output files.

If you have any questions, please contact me at (701) 355-5655.

Sincerely,

Jerry Menge
Air Quality Program Coordinator

jm:mev
Enclosures

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Acronyms and Abbreviations

°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
ACC	Air Cooled Condenser
AQD	Air Quality Division
AQRV	air quality-related values
BACT	Best Available Control Technology
BEPC	Basin Electric Power Cooperative
BPIP	Building Profile Input Program
Btu/yr	British thermal unit per year
CAA	Clean Air Act
CALMET	Meteorological Processor for the CALPUFF Modeling System
CALPOST	Post-Processor for the CALPUFF Modeling System
CALPUFF	Long-Range Transport Air Dispersion Model System
CAM	Compliance Assurance Monitoring
CAMR	Clean Air Mercury Rule
CEMS	continuous emission monitoring system
CDS	circulating dry scrubber
CFM	cubic feet per minute
CFR	Code of Federal Regulations
CO	carbon monoxide
COMS	continuous opacity monitoring system
CPM	condensable particulate matter
CTG	composite theme grid
CVAAS	cold-vapor atomic absorption
CVAFS	cold-vapor atomic fluorescence spectroscopy
DAT	Deposition Analysis Threshold
DEM	Digital Elevation Model
DOE	Department of Energy
EC	Exposure concentration
EC	elemental carbon
EPA	United States Environmental Protection Agency
ESP	electrostatic precipitator
FEL	federally enforceable limit
FGD	flue gas desulfurization
FLAG	Federal Land Managers' Air Quality Related Values Workgroup
FLM	Federal Land Manager
FR	Federal Register

g/s	grams per second
GEP	good engineering practices
gr/dscf	grains per dry standard cubic foot
H_2SO_4	sulfuric acid mist
HAP	hazardous air pollutant
HCl	hydrochloric acid
HF	hydrogen fluoride
Hg	mercury
$HgCl_2$	mercuric chloride
HNO_3	nitric acid
hp	horsepower
ICR	Information Collection Request
IMPROVE	Interagency Monitoring of Protected Visual Environment
ISC3	Industrial Service Complex
ISCST3	Industrial Source Complex Short-Term
IWAQM	Interagency Workgroup on Air Quality Modeling
K	Kelvin
kg/ha/yr	kilograms per hectacre per year
km	kilometer
kW	kilowatt
kWh	kilowatt hour
LAER	lowest achievable emission rate
lb	pound
lb/hr	pound per hour
lb/mmBtu	pounds of emissions per million British Thermal Units heat input
LCC	Lambert Conformal Conic
LNB	low NO_x burner
LOI	loss on ignition
m	meter
m/s	meters per second
MACT	Maximum Achievable Control Technology
MEI	maximum exposed individual
mg/M^3	milligrams per cubic meter
MM4	Mesoscale Model Version 4
MM5	Mesoscale Model Version 5
mmBtu/hr	million British thermal units per hour
MPRM	Meteorological Processor for Regulatory Models
msl	mean sea level
MW	megawatt
MWC	municipal waste combustors
MWH	megawatt per hour

N	nitrogen
NAAQS	National Ambient Air Quality Standards
NAD 27	North American Datum of 1927
NCDC	National Climatic Data Center
NDIR	nondispersive infrared
NED	National Elevation Dataset
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NMOC	nonmethane organic carbon
NO_2	nitrogen dioxide
NO_x	nitrogen oxide
NP	National Park
NPS	National Park Service
NRA	National Recreation Area
NRCS	National Resource Conservation Service
NSPS	New Source Performance Standards
NSR	New Source Review
NWS	National Weather Service
O_2	oxygen
OFA	over-fire air
PAH	poly aromatic hydrocarbons
PAL	plant-wide applicability limit
Pb	lead
PC	pulverized coal
PIC	product of incomplete combustion
PM	particulate matter
PM_{10}	particulate matter less than 10 micrometers in diameter
PPA	Pre-Project Actual
ppb	parts per billion
ppm	parts per million
PPP	Post-Project Potential
PRB	Powder River Basin
PRIME	Plume Rise Model Enhancements
PSD	Prevention of Significant Deterioration
psia	per square inch absolute
psig	per square inch gauge
PTE	potential to emit
PUC	public utility commission
QA	quality assurance
QC	quality control
RACT	Reasonable Available Control Technology

RBLC	RACT/BACT/LAER Clearinghouse
RCRA	Resource Conservation and Recovery Act
RICE	reciprocating internal combustion engines
RMP	Risk Management Plan
RSC	reduced sulfur compound
S	sulfur
SCR	selective catalytic reduction
SDC	submerged drag conveyor
SER	Significant Emissions Rate
SIL	Modeling Significance Level
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_4	sulfate
SOFA	Separate Overfire Air
SRDT	solar radiation/delta-T
tph	tons per hour
tpy	ton per year
TRS	total reduced sulfur
TSDF	treatment, storage, and disposal facility
TSL	toxic screening level
US	United States
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
UV	ultraviolet
VFD	variable frequency drive
VOC	volatile organic compound
WA	Wilderness Area
WAQS&R	Wyoming Air Quality Standards and Regulations
WAAQS	Wyoming Ambient Air Quality Standards
WDEQ	Wyoming Department of Environmental Quality

WDEQ

Application

Form

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

PERMIT APPLICATION FORM

Date of Application: 11/10/2005

1. Name of Firm or Institution Basin Electric Power Cooperative

2. Mailing Address

1717 East Interstate Avenue		Bismarck	ND
Number	Street	City	State

Burleigh	58503	701-223-0441
County	Zip	Telephone

3. Plant Location

Highway 59	North of Gillette		Wyoming
Number	Street	City	State

Campbell		701-355-5655
County	Zip	Telephone

4. Name of owner or company official to contact regarding air pollution matters

Jerry Menge	Air Quality Program Coordinator	701-355-5655
Name	Title	Telephone

1717 East Interstate Avenue		Bismarck	ND	58503
Number	Street	City	State	Zip

5. General nature of business

Coal Fired Electric Generation

6. Permit application is made for: _X_ New Construction ___ Modification
___ Relocation ___ Operation

7. Type of equipment to be constructed, modified, or relocated. (List each <u>major</u> piece of equipment separately.)

Pulverized Coal Fired Boiler

Material Handling Dust Collectors

8. If application is being made for operation of an existing source in a new location, list previous location and new location:

Previous Location: Not Applicable

New Location: Not Applicable

9. If application is being made for a crushing unit, is there: (mark all appropriate boxes)

Primary Crushing	Coal Crusher	Control Equipment:	Dust Collector
Secondary Crushing		Control Equipment:	-
Tertiary Crushing		Control Equipment:	-
Recrushing & Screening		Control Equipment:	-
Conveying		Control Equipment:	-
Drying		Control Equipment:	-
Other		Control Equipment:	-

Proposed dates of operation (month/year): January 2011

10. Materials used in unit or process (include solid fuels):

Type of Material	Process Weight Average (lb/hr)	Process Weight Maximum (lb/hr)	Quantity/Year
Coal	461,156	487,308	2,019,696 tons/yr

11. Air contaminants emitted: Please see Section 3

Emission Point	Pollutant	lb/hr	ton/yr	Basis of Data

12. Air contaminant control equipment:

Emission Point	Type	Pollutant Removed	Efficiency
PC Boiler	Fabric Filters	PM/PM_{10}	See Note Below
	Low NOx Burners & SCR	NOx	See Note Below
	Dry Lime FGD	SO_2	See Note Below
Material Handling Sources	Fabric Filters/Bin Event Filters	PM/PM_{10}	See Note Below
Fugitive Sources	Paving/Water Sprays	PM/PM_{10}	See Note Below

~~Note: Please refer to Section 2 and Section 5 for more information on Control Equipment~~

13. Type of combustion unit: (check if applicable):

A. Coal X

1. *Pulverized* X:

General __; Dry Bottom X; Wet Bottom __; With Flyash Reinjection __;
Without Flyash Reinjection __; Other __________

2. *Spreader Stoker* __:

With Flyash Reinjection __; Without Flyash Reinjection __; Cyclone __;
Hand-Fired __; Other __________

B. Fuel Oil __

Horizontally Fired __ Tangentially Fired __

Type of combustion unit: (check if applicable):

C. Natural Gas __

D. If other, please specify __________

Hourly fuel consumption (estimate for new equipment) 487,308 LB /hr.

Size of combustion unit 3,801x10^6 BTU heat input/hour.

14. Operating Schedule: 24 hours/day; 7 days/week; 52 weeks/year.

Peak production season (if any): __________

15. Fuel analysis:

	COAL	FUEL OIL	NATURAL GAS
% Sulfur	0.47		
% Ash	4.77		
BTU Value	7,800		

16. Products of process or unit:

Products	Quantity/Year
Electricity	3,224,915 Net MW-HR/YR

17. Emissions to the atmosphere (each point of emission should be listed separately and numbered so that it can be located on the flow sheet): Please see attached Table 1

Emission Point	Stack Height (ft)	Stack Diameter (ft)	Gas Discharge SCFM	Exit Temp (^{o}F)	Gas Velocity (ft/s)

18. Does the input material or product from this process or unit contain finely divided materials which could become airborne?

_X_ Yes ___ No

Is this material stored in piles or in some other way as to make possible the creation of dust problems?

___ Yes _X_ No

18. Continued:

List storage pile (if any): Not Applicable

Type of Material	Particle Size (Diameter or Screen Size)	Pile Size (Average Tons on Pile)	Pile Wetted (Yes or No)	Pile Covered (Yes or No)

19. Using a flow diagram: Please see Appendix A

(1) Illustrate input of raw materials.

(2) Label production processes, process fuel combustion, process equipment, and air pollution control equipment.

(3) Illustrate locations of air contaminant release so that emission points under items 11, 12 and 17 can be identified. For refineries show normal pressure relief and venting systems. Attach extra pages as needed.

20. A site map should be included indicating the layout of facility at the site. All buildings, pieces of equipment, roads, pits, rivers and other such items should be shown on the layout. Please see Appendix A

21. A location drawing should be included indicating location of the facility with respect to prominent highways, cities, towns, or other facilities (include UTM coordinates). Please see Appendix A

"I certify to the accuracy of the plans, specifications, and supplementary data submitted with this application. It is my Opinion that any new equipment installed in accordance with these submitted plans and operated in accordance with the manufacturer's recommendations will meet emission limitations specified in the Wyoming Air Quality Standards and Regulations."

Signature		Typed Name	James K. Miller		
Title	Manager, Environmental Services	Company	Basin Electric Power Cooperative		
Mailing Address	1717 East Interstate Avenue	Telephone No.	701-223-0441		
City	Bismarck	State	ND	Zip	58503
P.E. Registration (if applicable)					
State where registered					

WDEQ Permit Application Form
Table 1

Emission Point	Stack Height (ft.)	Stack Diameter (ft.)	Gas Discharge (SCFM)	Exit Temperature (F)	Gas Velocity (ft./s)
ES1-02	232	4.00	26,582	305	59.4
ES1-03	20.0	0.25	358	845	350
ES1-04	15.0	8.00	54,997	77.0	21.6
ES1-05	20.0	1.00	1,892	855	116
ES1-06	30.0	2.50	1,391	600	11.0
ES1-07	180	2.25	15,060	68.0	73.4
ES1-08	180	2.25	15,060	68.0	73.4
ES1-09	180	1.83	9,724	68.0	71.3
ES1-10	156.0	3.08	27,710	68.0	71.9
ES1-11	210	3.25	30,119	68.0	70.3
ES1-12	100	1.37	800	68.0	49.7
ES1-13	80.0	0.97	1,100	68.0	49.8
ES1-14	88.0	1.67	5,163	200	57.3
ES1-15	88.0	1.67	5,163	200	57.3
ES1-16	88.0	2.25	18,000	68.0	87.3
ES1-17	88.0	2.25	18,000	68.0	87.3
ES1-18	97.0	0.97	1,900	68.0	49.8
ES1-19	97.0	0.97	1,900	68.0	49.8
ES1-20	86.0	0.50	800	68.0	78.6
ES1-21	32.0	0.83	1,200	150	49.4
ES1-22	95.0	0.83	1,250	200	55.7

Notes:
Standard Temperature = 68 F
Standard Pressure = 14.7 psi
Ambient Pressure = 12.65 psi at 4,250 amsl

Section 1

Introduction

SECTION 1.0

Introduction

Basin Electric Power Cooperative (BEPC) proposes to construct a new coal fired electric power generating station adjacent to the Dry Fork Mine northeast of Gillette, Wyoming. The proposed project, the Dry Fork Station Project, would include one pulverized coal (PC) boiler that would be capable of generating a maximum 422 MW of power (gross). This document serves as an application to the Wyoming Department of Environmental Quality (WDEQ) Air Quality Division (AQD) for a construction permit in accordance with Wyoming Air Quality Standards and Regulations (WAQS&R). As a "major emitting facility" as defined in Chapter 6, Section 4.0 of the WAQS&R, the project will be subject to Prevention of Significant Deterioration (PSD) rules.

This application includes the WAQS&R Chapter 6, Section 2.0 permit application form, a project description, emissions information, regulatory review, a Best Available Control Technology (BACT) analysis, a description of requested permit limits, descriptions and results of Class I and Class II area air quality dispersion modeling, monitoring information, and a compliance plan.

1.1 Project Emission Levels

Emissions from the Dry Fork Station will exceed PSD significant annual emission rates and will therefore be subject to review under PSD rules for carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), volatile organic compounds (VOC), sulfur dioxide (SO_2), nitrogen oxides (NO_x), sulfuric acid mist (H_2SO_4), beryllium (Be), and fluorides (as HF).

The Dry Fork Station will be located in an attainment area for all criteria pollutants. The project will meet all National Ambient Air Quality Standards (NAAQS) and Class II PSD increments in the vicinity of the plant, and Class I increments at distant Class I areas.

The Dry Fork Station will also be a major emitter of hazardous air pollutants (HAPs) as defined in the Clean Air Act at 42 U.S. C. § 7412(g)(2). Dry Fork Station will comply with the newly promulgated mercury emission standard of 78×10^{-6} lbs/MWH but is not subject to a requirement to perform a maximum achievable control technology (MACT) analysis for this or other HAPs.

1.2 Overview

The addition of the Dry Fork Station will result in additional power generating capacity to sustain current and future power demands in the BEPC service area. This project will result in economic benefit through the creation of jobs during facility construction, permanent jobs during startup and operation, and employment opportunities associated with facility support.

State-of-the-art pollution controls are proposed for the Dry Fork Station that will make the project one of the cleanest coal-fired power plants in the nation. Pollution controls include selective catalytic reduction (SCR) to control NO_x, dry lime flue gas desulfurization to control SO_2, a fabric filter to control particulate matter and the ability to add sorbent injection (e.g. activated carbon) for mercury control (if needed at a future date).

1.3 Permit Application Organization

This application document is organized into ten sections and seven appendices:

- **WDEQ Permit Application Form**
- **Section 1.0 – Introduction.** This section provides an overview of the project and describes the report organization.
- **Section 2.0 – Project Description.** This section includes a detailed description of the proposed project including the boiler, emission control equipment, and material handling systems.
- **Section 3.0 – Emissions Summary.** This section provides a summary of emissions related information, including boiler stack and auxiliary equipment emissions, and material handling emission estimates.
- **Section 4.0 – Regulatory Applicability Review.** This section contains a detailed regulatory review of all state and federal air regulations that may impact the permitting, construction, or operation of the proposed project.
- **Section 5.0 – Control Technology Analysis.** This section includes a control technology analysis for criteria pollutants (BACT Analysis), a discussion of the Clean Air Mercury Rule (CAMR) relating to the main boiler and a MACT analysis for the auxiliary boiler.
- **Section 6.0 – Requested Permit Limits.** This section presents a discussion of requested permit limits to reflect consistency with assumptions made in the analysis of project related emissions.
- **Section 7.0 – Near-Field Air Quality Impact Analysis.** This section includes the Class II area (near-field) air quality modeling analyses, including a review of growth impacts and impacts to soils and vegetation.
- **Section 8.0 – Far-Field Air Quality Impact Analysis.** This section includes the modeling analyses for Class I and Class II areas located more than 50 kilometers from the proposed project, including analyses for visibility, criteria pollutant impacts, and deposition.
- **Section 9.0 – Monitoring Information.** This section presents monitoring-related information.
- **Section 10.0 – Compliance Plan and Certification.** This section presents information relative to the compliance plan for the project.
- **Appendix A – Process Flow Diagrams.** This appendix includes process flow diagrams and general arrangement drawings for the project.

- **Appendix B – Emissions Calculations.** This appendix provides the calculations that were used to determine the criteria and HAP emissions for this permit application.
- **Appendix C – Summary of Wyoming (WAQS&R) Regulatory Review Requirements.** This appendix includes regulatory review tables for the Wyoming air quality regulations.
- **Appendix D – Summary of Federal Regulatory Review Requirements.** This appendix includes regulatory review tables for federal air quality regulations.
- **Appendix E – RACT/BACT/LAER Clearinghouse Data.** This appendix includes a list of recently issued PSD permit limits and a print out of RBLC database tables used for the BACT analysis.
- **Appendix F – BACT Cost Analysis.** This appendix includes documentation for the BACT cost analysis.
- **Appendix G – Supporting Documentation for Near-Field Modeling.** This appendix provides supporting documentation for the near-field modeling analysis.
- **Appendix H – Supporting Documentation for Far-Field Modeling.** This appendix provides supporting documentation for the far-field modeling analysis.

Section 2

Project Description

SECTION 2.0

Process Description

2.1 Facility Description

Basin Electric Power Cooperative (BEPC) proposes to construct the Dry Fork Station Project near Gillette, Wyoming approximately four miles northeast of the Gillette-Campbell County Airport. (Figure 2-1). The proposed power plant would include one pulverized coal (PC) boiler that would be capable of generating a maximum of 422 MW gross and 385 MW net.

2.1.1 General Process Description

Figure 2-2 is a general process flow diagram for the Dry Fork Station. The generating plant produces electricity by combusting coal in a boiler to produce heat to convert water to steam. The steam powers a turbine that turns an attached electric generator producing electricity.

The Dry Fork Station consists of the following components:

1. Boiler
2. Turbine
3. Generator
4. Air-cooled Condenser
5. Auxiliary Equipment (auxiliary boiler, emergency generator, fire pump, fuel gas heater, auxiliary cooling tower)
6. Fuel Handling System
7. Emissions Control Equipment
8. Other Material Handling Systems (ash, lime, sorbent)

In the Dry Fork Station's coal fired boiler, tubes containing water line the inside of the furnace walls. The coal that enters the furnace is ignited and burned. The burning coal releases thermal energy, which is absorbed by the water in the tubes. The temperature of the water rises and the water boils, producing steam. The steam is piped from the boiler to the steam turbine.

The steam turbine is comprised of blades attached to a rotating shaft. The Dry Fork Station steam turbine has both stationary and rotating blades. As the high-pressure steam from the boiler passes through the turbine blades, the pressure and thermal energy of the steam is converted to mechanical energy, causing the rotating set of blades to turn the shaft of the turbine. The steam turbine shaft is coupled to the shaft of the electrical generator. The generator converts the mechanical energy of the rotating shaft into electric energy.

After the steam passes through the turbine, it flows into the air-cooled condenser (ACC). In the ACC, the steam is cooled and condensed back into water. The water is then pumped back to the boiler through a series of low-pressure feedwater (condensate) heaters, a deaerator, and several high-pressure feedwater heaters. The water is then pumped back into the tubes of the boiler to be made again into steam. The heaters increase the efficiency of the overall process.

The complete water and steam loop from the boiler, through the turbine, into the condenser, through the condensate and feedwater systems, and back to the boiler is called the condensate-feedwater steam cycle.

The major component systems of the proposed Dry Fork Station are as follows:

1. Fuel Handling
2. Generating Unit
3. Emissions Control Equipment
4. Material Handling

These systems consist of the following sub-systems:

Fuel Handling

a. Coal Handling
b. Diesel Fuel System
c. Natural Gas System

Generating Unit

a. Boiler
b. Steam Turbine
c. Boiler Feedwater System
d. Air-cooled Condenser

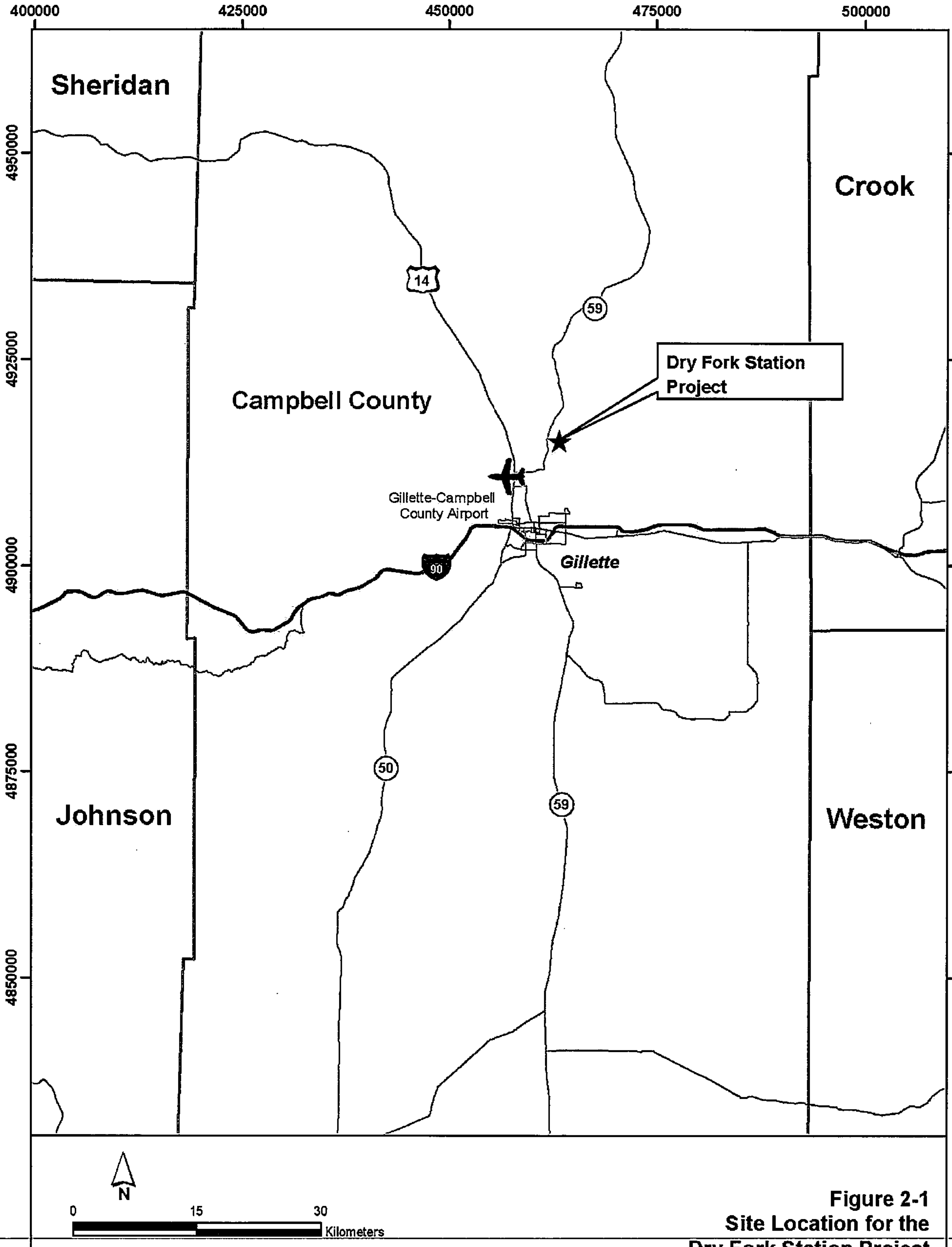
Emissions Control Equipment

a. Low- NO_x Burners and Overfire Air
b. Selective Catalytic Reduction System
c. Dry Scrubber System
d. Fabric Filter
e. Sorbent injection (e.g. activated carbon) system

Material Handling

a. Fly Ash Collection, Transport and Disposal
b. Bottom Ash Collection, Transport and Disposal
c. Lime Unloading, Storage and Transport
d. Anhydrous Ammonia Unloading, Storage and Transport
e. FGD Waste Collection, Transport and Disposal

The summary description for the Dry Fork Station provided below includes a description of those systems which contain or affect this facility's air emissions. Other systems, not containing or impacting air emissions, or those systems with air emissions deemed insignificant by the WDEQ are not included in this process description.



Coordinates refer to UTM Zone 13N, NAD83

Figure 2-1
Site Location for the
Dry Fork Station Project

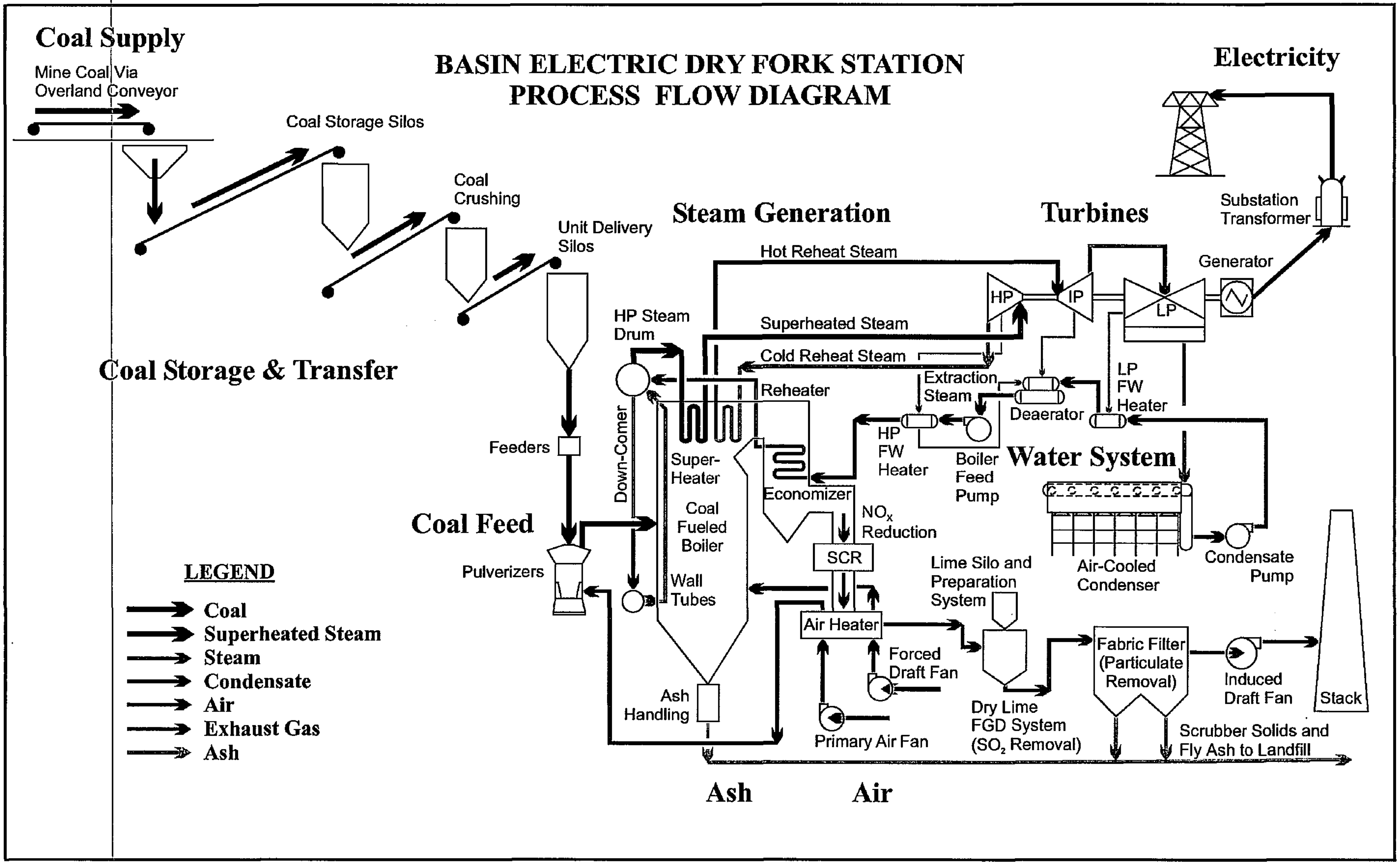


FIGURE 2-2
General Process Diagram for Dry Fork Station

2.1.1.1 Unit #1 Process Description

The source of coal for the project will be the adjacent Dry Fork Mine. Coal from the mine, will be delivered to the power plant via a covered, overland conveyor belt. The proposed primary fuel will be a sub-bituminous coal. Natural gas will be used for light off, startup, and flame stabilization. Coal and natural gas burner configurations and combustion control systems will be designed to provide high combustion efficiency and to control the production of NO_x in the flue gas.

Emissions associated with the PC boiler will be controlled through various reduction methods. The sulfur dioxide (SO_2) emissions will be controlled with a dry lime flue gas desulfurization (FGD) system. Boiler particulate emissions will be controlled with a fabric filter dust collector (baghouse). Emissions of nitrogen oxides (NO_x) will be controlled with a combination of low NO_x burners (LNBs), overfire air (OFA) and Selective Catalytic Reduction (SCR). Mercury will be controlled with the FGD and baghouse system and additional sorbent injection (e.g. activated carbon) as needed.

Cooling of steam to condensate-feedwater will be done through an air cooled condenser. The Dry Fork Station will conserve water by not having a conventional wet cooling tower to assist in the condensation of the steam in the turbine exhaust back into water. There will be a small auxiliary wet cooling tower to cool various pieces of process equipment in the Station such as air compressors, but the main plant cooling will be done with a dry condenser. Process flow diagrams showing details for the various components of the Dry Fork Station are located in Appendix A. Figure A-1 shows the general arrangement of the property and Figure A-2 shows the general arrangement and layout of the plant. Specific emission points and details associated with those emission points are shown on Figures A-3 and A-4.

The flue gas from the boiler will pass through the SCR, FGD and fabric filter emission control systems then through the induced draft fans and will be exhausted through a stack to the atmosphere. The stack will be 500 feet tall and will consist of an outer concrete wind shell and an inner flue. A continuous emission monitoring system (Part 75 CEMS) and COMS will be provided to monitor emissions.

Boiler

The proposed Unit 1 boiler will be an indoor-type pulverized coal fired boiler designed for "base load" operation. The unit will have a maximum gross heat input of approximately 3,801 MMBtu/hr, a maximum gross generation output of 422 MW and a maximum net generation output of 385 MW. The primary fuel for Unit 1will be Dry Fork Mine subbituminous coal. Natural gas will be used as the start-up fuel and for use in the auxiliary boiler. Gross and net generation at average plant conditions is expected to be somewhat lower.

It is anticipated that the Unit 1 boiler will be a dry-bottom, tangentially-fired or wall-fired (front and rear) boiler with low NO_x burners and overfire air ports. Specifications for the proposed boiler are included in Table 2-2. Flue gas from Unit 1 will pass through a series of post-combustion emission control devices, described in Section 2.2 of this permit application, and discharge through one 500-foot stack.

The boiler area will be a totally enclosed design. Burners will be located at various levels either in the four corners or in the front and back furnace walls. The coal silos will be located along the boiler front, with an enclosed coal tripper gallery. The principal components of the boiler will be:

- membrane wall furnace
- superheater
- reheater
- economizer
- convection pass
- coal feeders
- coal pulverizers
- low NO_x burners (LNBs), overfire air ports, fans, and air heater
- induced draft, forced draft and primary air fans
- air preheaters
- boiler wall cleaning/sootblowing system
- flues and ducts
- piping and valves

TABLE 2-1
Coal Characteristics (As Received Proximate)

Parameter	Unit	Design	Minimum	Maximum
Gross (Higher) Heating Value	Btu/lb	8,045	7,800	8,300
Moisture	wt %	32.1	30.5	33.8
Volatile Matter	wt %	30.1	28.0	32.0
Sulfur Content	wt %	0.33	0.25	0.47
Ash Content	wt %	4.8	4.2	6.5
Maximum Uncontrolled SO_2 Emission Rate	lb/mmBtu	0.82	0.60	1.21

TABLE 2-2
Boiler Parameters

Plant Parameter	Unit	Design Maximum
Gross Plant Output	Gross-kW	422,000
Net Plant Output	Net-kW	385,000
Full Load Heat Input to Boiler	mmBtu/hr	3,801
Coal Feed Rate	lb/hr	487,319

2.2 Emissions Control Equipment

2.2.1 Flue Gas Desulfurization System

The Unit 1 boiler unit will be equipped with a dry lime flue gas desulfurization (FGD) system. The FGD system, located upstream from the fabric filter, removes sulfur dioxide (SO_2) from the flue gas stream by use of a lime slurry absorption process. Additional details on the lime FGD process are provided in the BACT analysis section of this application in Section 5.0.

The FGD system will be designed to consistently achieve a controlled SO_2 emission rate of 0.10 lb/mmBtu on a 3-hour block average basis. Assuming a maximum uncontrolled SO_2 emission rate of 1.21 lb/mmBtu, this represents an overall SO_2 removal efficiency of approximately 91.7 percent.

Preliminary design and operating parameters for the FGD system are summarized in Table 2-3.

TABLE 2-3
Flue Gas Desulfurization Operating Parameters

Parameter	Unit	Design
General Description		Dry Lime FGD
Number of Scrubber Modules		2
Flue Gas Flow Rate	acfm	1,477,829
Flue Gas Temperature (inlet)	°F	284
Flue Gas Temperature (outlet)	°F	170
Inlet SO_2 Emission Rate	lb/mmBtu	0.82 to 1.21
Outlet SO_2 Emission Rate	lb/mmBtu	0.10
SO_2 Collection Efficiency	%	92
HCl Collection Efficiency	%	90
HF Collection Efficiency	%	90
Calcium to Sulfur Molar Ratio		1.30
Lime Feed Rate	lb/hr	5,790

2.2.2 Low NO_x Burners and Selective Catalytic Reduction

Unit 1 will have LNBs to reduce the formation of NO_x in the combustion process in the boiler. Low NO_x burners control the formation of NO_x by staging the combustion of the coal to keep the peak flame temperature below the threshold for NO_x formation. The burner initially introduces the coal into the boiler with less air than is needed for complete combustion. The flame is then directed toward an area where additional combustion air is introduced from OFA ports allowing final combustion of the fuel. Unit 1 will also be equipped with a selective catalytic reduction (SCR) reactor to reduce NO_x emissions from the boiler. SCR is the state-of-the-art technology for the reduction of NO_x from flue gas streams. The proposed SCR will be designed for high dust loading applications, and will be located external from the boiler at the outlet of the boiler economizer section. The SCR will use anhydrous ammonia to react with NO_x in the flue gas to produce nitrogen gas and water. Additional details on the SCR process are provided in the BACT analysis in Section 5.0.

Based on technical information provided by boiler vendors, it is anticipated that NO_x emissions from the boiler (prior to the SCR) can be controlled with low NO_x burners and overfire air to 0.20 to 0.25 lb/mmBtu (approximately 148 to 185 ppmvd at 3 percent O_2) while maintaining acceptable levels of CO and VOC. Assuming a NO_x inlet concentration of 148 to 185 ppmvd at 3 percent O_2, the SCR will be designed to reduce the NO_x concentration to approximately 50 ppmvd at 3 percent O_2, or 0.07 lb/mmBtu. This represents an overall removal efficiency of approximately 65 to 72 percent.

The preliminary SCR operating parameters are summarized in Table 2-4.

TABLE 2-4
SCR Operating Parameters

Parameter	Unit	Estimated Design Value
Maximum Ammonia Feed Rate	lb/hr	196
NOx Inlet Concentration	ppmvd @ 3% O_2	148 -185
NOx Inlet Emission Rate to SCR	lb/mmBtu	0.20 – 0.25
NOx Outlet Concentration	ppmvd @ 3% O_2	50
NOx Outlet Emission Rate	lb/mmBtu	0.07
NOx Control Efficiency	%	66 - 72
Ammonia Slip	ppmvd @ 3% O_2	2
Catalyst Life	years	2 - 3

2.2.3 Fabric Filter

A fabric filter dust collector system (or "baghouse") will be provided for Unit 1 to remove particulate matter from the boiler flue gas stream. The fabric filter system will consist of a number of compartments containing fabric filter bags fitted over a wire cage and suspended from a horizontal tube sheet in the compartment. Additional details on the baghouse particulate removal process are provided in the BACT analysis Section 5.0.

The fabric filter system will be designed to achieve a maximum filterable PM_{10} emission rate of 0.012 lb/MMBtu with a design collection efficiency of 99.8 percent. The maximum filterable PM emission rate will be 0.015 lb/mmBtu. Anticipated fabric filter system parameters are summarized in Table 2-5.

TABLE 2-5
Anticipated Fabric Filter Design Parameters

Parameter	Units	Estimated Design Value
Flue Gas Flow Rate to Fabric Filter	acfm	1,507,797
Inlet Gas Temperature	°F	170
Inlet Total Particulate Loading	lb/hr	18,596
Outlet Total Particulate Loading	lb/hr	45.6
Collection Efficiency	%	99.80
Outlet PM Emission Rate	lb/mmBtu	0.015
~~Outlet PM$_{10}$ Emission Rate~~	~~lb/mmBtu~~	~~0.012~~

2.2.4 Sorbent Injection System

A sorbent injection system using activated carbon or other suitable sorbent material may be provided for Unit 1 to remove mercury from the boiler flue gas stream. Additional details on the mercury removal process are provided in the BACT analysis Section 5.0.

2.3 Coal Handling System

The coal handling system design can be found in Appendix A Figure A-5, Coal Flow Diagram. Coal is received at the station from the Dry Fork mine via a 48-inch-wide overland belt conveyor. The conveyor will be approximately 2,700 feet in length and will transport coal at a rate of 1,350 tons per hour (tph) from the mine to the transfer house (transfer house 2). From the transfer house, coal is then conveyed to the three coal storage silos. Coal can also be sent directly to the coal crusher house from the transfer house via a 42-inch-wide conveyor, bypassing the coal silos. The Crusher House incorporates a surge bin with two vibratory feeders each discharging to a crusher. The coal is then loaded onto one of two 900 tph, 42-inch-wide conveyors. These conveyors convey the coal to the plant's transfer conveyor bay. The coal is discharged from the transfer conveyor bay onto two 900 tph tripper conveyors (K1 and K2). The tripper conveyors feed the six in-plant coal silos for Unit 1 located next to the boiler.

In an emergency, coal can also be delivered via truck into a below ground truck hopper. The coal from the truck hopper is conveyed to transfer house 2, then to the coal silos. From the coal silos, the coal is transferred via enclosed conveyor to the coal crusher house.

2.3.1 Dust Control

The coal handling system employs a number of effective mechanisms for minimizing fugitive dust emissions.

- All coal transfer buildings and the crusher building are enclosed.
- Bag house type dust collection systems are provided for each of the enclosed conveyor transfers and the crushers. Dry fogging may also be used.

2.4 Material Handling

2.4.1 Scrubber Additive (Lime) Handling and Preparation System

The FGD system utilizes lime to remove SO_2 from the flue gas and therefore requires a lime handling system, which receives, stores and processes crushed lime. Although several different technologies are available, this description reflects use of a circulating dry lime FGD system.

Lime will be delivered to the Station by truck and trailer. The trailers are totally enclosed, over the road, 25-ton capacity trailers. The truck will park next to the lime unloading building, and connect a rubber conveyance hose to the trailer and to a fixed conveyance pipe for the lime storage silo. The truck will use its own compressor system to pneumatically offload the lime to the storage silo. From the storage silo, lime is transferred to the lime day bin.

A day bin with a 24-hour capacity will be located in the reagent preparation building to supply lime to the conditioning equipment. The day bin level will be maintained by pneumatically transferring the lime from the storage silo to a transfer hopper, which then discharges into a conveyance pipe and conveys the lime using positive pressure to the day bin. From the lime day bin, lime is conveyed to mixer seasoning chambers where the lime is hydrated before it is sent to the hydrated lime crusher by screw conveyor. From the hydrated lime crusher, the crushed hydrated lime is pneumatically transferred to one of two hydrated lime silos. From the hydrated lime silos, the material is then utilized by the dry scrubber system to remove SO_2 from the flue gas stream.

To control emissions generated from the lime, the system is equipped with a dust collection system and bin vent filters on the storage silo, and day bin. Figure A-8 in Appendix A shows the lime and hydrated lime material handling system.

2.4.2 Fly Ash and FGD Waste Handling System

Fly ash and dry lime FGD waste entrained in the hot boiler flue gas will be removed from the flue gas using a fabric filter baghouse. Ash will also be collected from other various locations throughout the duct work system by means of ash hoppers located beneath the collection locations where the flue gas becomes stagnate and ash tends to settle out. The flyash/FGD waste handling system will be comprised of an independent pneumatic ash conveyance and storage system. The fabric filter baghouse will have an ash hopper beneath each compartment connected to the ash conveyance system.

The fly ash/FGD waste will be transported through vacuum conveyance lines to the filter separators located on top of the ash storage silo. The filter separators will discharge the collected fly ash/FGD waste into transfer hoppers and then directly into the ash silo. The filter separators will be designed with sufficient bag filtering capacity to control emissions, along with a bin ventilation filter, which will be responsible for filtering the displaced silo air. Electric motor-driven vacuum exhausters will provide conveying air for the system.

As the silo becomes full, ash will be periodically removed from the silo into trucks. The ash will pass through a water and ash mixer (pin mixer) to condition the fly ash/FGD waste prior to loading onto trucks for haulage to the ash landfill. The bottom of the storage silo will also be equipped with a complete fluidizing air system to fluidize the stored ash so it will flow through the conditioning system into the haul truck. The fluidizing air system includes a porous fluidizing media, that will use air from air blowers. Figure A-7 in Appendix A shows the ash and FGD waste handling system.

2.4.3 Bottom Ash Handling System

Furnace ash from the steam generator furnace collects in the bottom of the boiler in a water filled trough. The bottom ash is removed by a submerged drag conveyor (SDC) on a continuous basis. Seal plates secured to the steam generator tubes are suspended in the SDC trough to form the furnace water seal. The collected bottom ash will be dragged along the conveyor up an incline where it will be dewatered before being discharged into an outdoor storage bunker.

Mill rejects from the coal mill reject hoppers will be conveyed by hydro-ejectors to the SDC trough. The mill rejects will combine with the furnace ash and will be conveyed to a bottom ash storage area as described above.

The Economizer ash will be collected with dry flight conveyors. Economizer ash also be combined with the bottom ash and will be conveyed to a bottom ash storage area as described above.

Material from the bottom ash storage area will be loaded into trucks by a front end loader and hauled to the ash landfill for disposal. Figure A-6 in Appendix A shows the economizer bottom ash and mill rejects ash handling system.

2.4.4 Sorbent Injection System (Activated Carbon Handling)

A sorbent injection system may be installed to remove additional mercury from the flue gas.

Sorbent reagent (e.g. activated carbon) would be delivered to the Station by truck and trailer. The trailers are totally enclosed, over the road, 25-ton capacity trailers. The trucks would park next to the sorbent preparation building and connect a rubber conveyance hose to the truck and to a fixed conveyance pipe for the storage silo. The trucks would use their own compressor system to pneumatically offload the sorbent to the storage silo. While filling the storage silo, an exhaust filter on top of the storage silo filters the displaced air.

To control emissions generated from the handling of the sorbent, the system is equipped with a dust collection system at the discharge of the screw conveyor and along the bucket elevator. This is piped to the bin vent filters on the storage silos.

The sorbent will be taken from the storage silo and metered into an injection system. The injection system will use compressed air to carry the sorbent to a series of injection nozzles located in the boiler flue gas duct upstream of the dry lime FGD system or the baghouse system. The sorbent will capture mercury in the flue gas and will be collected in the baghouse along with the fly ash and waste material from the FGD system. Figure A-9 in Appendix A shows the activated carbon material handling system.

2.4.5 Anhydrous Ammonia Unloading/Storage System

Anhydrous ammonia will be transported to plant by truck and stored in large gas storage vessels. The gaseous ammonia will then be piped to injection nozzles in the boiler flue gas exit duct upstream of the SCR system. The combined ammonia and flue gas will enter the SCR system and pass over the catalyst where the NO_x in the flue gas reacts with the ammonia to form nitrogen gas and water. The use of anhydrous ammonia will require the submittal of a Risk Management Plan (RMP) per 40 CFR Part 68 requirements.

Section 3
Emissions Summary

SECTION 3.0

Emissions Summary

Emission estimates were prepared for all point and fugitive emissions sources from the Dry Fork Station including the main PC boiler, material-handling sources, and auxiliary equipment. The Dry Fork Station will have material-handling operations for coal, flyash, flue gas desulfurization (FGD) waste, lime, sorbent (activated carbon), and ash disposal. Annual emissions were estimated based on 100 percent capacity factor (full load operation for 8,760 hours per year). BEPC may elect to install a sorbent injection system, using a material such as activated carbon, for reducing mercury emissions from the main boiler. Detailed emission calculations are provided in Appendix B.

The major air emission sources and regulated air pollutants for the project are shown in Table 3-1.

TABLE 3-1
Major Air Emission Sources and Regulated Air Pollutants

Source Number	Emission Point	Regulated Air Pollutants
ES1-01	Main Boiler – Unit 1 Stack	SO_2, NO_x, PM, PM_{10}, CO, VOC, Lead, Beryllium, Mercury, H_2SO_4, HF, HAPs
ES1-07, ES1-08, ES1-09, ES1-10, ES1-11	Coal Handling	PM, PM_{10}
ES1-12, ES1-13, ES1-14, ES1-15, ES1-16, ES1-17, ES1-18, ES1-19	Lime Handling	PM, PM_{10}
ES1-20	Mercury Sorbent (Activated Carbon) Handling	PM, PM_{10}
ES1-21, ES1-22, FS1-01	Fly Ash/FGD Waste Handling	PM, PM_{10}
FS1-02P, FS1-02UP	Fly Ash/FGD Waste Haul Roads – Paved and Unpaved	PM, PM_{10}
FS1-04P, FS1-04UP	Bottom Ash Haul Roads – Paved and Unpaved	PM, PM_{10}
FS1-03	Ash/FGD Waste Landfill	PM, PM_{10}

The air emission sources and regulated air pollutants for the auxiliary equipment are shown in Table 3-2.

TABLE 3-2
Auxiliary Equipment - Air Emission Sources and Regulated Air Pollutants

Source Number	Emission Point	Regulated Air Pollutants
ES1-02	Auxiliary Boiler	SO_2, NO_x, PM/PM_{10}, CO, VOC, Lead, HAPs
ES1-03	Fire Pump	SO_2, NO_x, PM/PM_{10}, CO, VOC, HAPs
ES1-04	Auxiliary Cooling Tower	PM, PM_{10}
ES1-05	Emergency Generator	SO_2, NO_x, PM/PM_{10}, CO, VOC, HAPs
ES1-06	Inlet Gas Heater	SO_2, NO_x, PM/PM_{10}, CO, VOC, Lead, HAPs

Emissions shown in the sections and tables below represent potential emissions of all pollutants (regulated and unregulated), are being presented to thoroughly describe the proposed facility, however, proposed permit limits are in listed in Section 6.3.

3.1 Unit 1 Boiler Criteria Emissions

The estimated hourly and annual controlled emission rates of criteria pollutants from ES1-01, the Unit 1 stack, are shown in Table 3-3. The hourly emissions are estimated at peak conditions and the annual emissions are estimated at 100 percent load operation for the entire year. The peak operating conditions assume a worst case coal analysis and maximum heat input to the boiler of 3,801 mmBtu/hr. The annual emissions assume an average expected coal analysis, heat input to the boiler of 3,701 mmBtu/hr and annual capacity factor of 100 percent.

TABLE 3-3
Unit 1 Boiler Criteria Pollutants

Pollutant	Hourly Emissions (pounds per hour [lb/hr])	Annual Emissions (tons per year [tpy])	PSD Significant Emission Rates (tpy)	Emission Factor Reference
Sulfur Dioxide	380	1,625	40	Engineering Estimates
Nitrogen Oxides	266	1,137	40	Engineering Estimates
Filterable Particulate Matter	57.0	244		Engineering Estimates
Total Particulate Matter	76.0	325	25	Engineering Estimates
Filterable Particulate Matter PM_{10}	45.6	195		Engineering Estimates
Total Particulate Matter PM_{10}	64.6	276	15	Engineering Estimates
Carbon Monoxide	570	2,437	100	Engineering Estimates
VOCs	14.6	60.6	40	AP-42 Table 1.1-19
Lead	0.006	0.03	0.6	Dry Fork Mine Coal Analysis
~~Beryllium~~	~~0.00097~~	~~0.0040~~	~~0.0004~~	~~Dry Fork Mine Coal~~ Analysis

TABLE 3-3
Unit 1 Boiler Criteria Pollutants

Pollutant	Hourly Emissions (pounds per hour [lb/hr])	Annual Emissions (tons per year [tpy])	PSD Significant Emission Rates (tpy)	Emission Factor Reference
Mercury	0.0113	0.047	0.1	Dry Fork Mine Coal Analysis
Sulfuric Acid Mist	9.5	40.6	7	Engineering Estimates
Fluorides (as HF)	2.6	11.2	3	Engineering Estimates

The total PM and PM_{10} emissions include filterable, condensable (hydrogen chloride, hydrogen fluoride, sulfuric acid, ammonium sulfate and organic condensables) and elemental carbon emissions.

3.2 Unit 1 Boiler Hazardous Air Pollutant Emissions

The estimated annual controlled emission rates of trace metal hazardous air pollutants (HAPs), organic compounds, and acid gas HAPs for ES1-01, the Unit 1 stack, are shown in Tables 3-4, 3-5, and 3-6. Unit 1 will be designed to burn coal from the adjacent Dry Fork Mine. The metal concentration was used to estimate the trace metal HAP emissions. Hourly emissions are estimated at peak operation for the boiler; and annual emissions are estimated at 100 percent capacity factor for the boiler.

TABLE 3-4
Unit 1 Boiler Trace Metal HAPs

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)	Emission Factor Reference
Antimony	3.23E-03	1.34E-02	Coal Analysis
Arsenic	3.23E-03	1.34E-02	Coal Analysis
Beryllium	9.68E-04	4.01E-03	Coal Analysis
Cadmium	6.45E-04	2.67E-03	Coal Analysis
Chromium	9.68E-03	4.01E-02	Coal Analysis
Cobalt	6.45E-03	2.67E-02	Coal Analysis
Lead	6.45E-03	2.67E-02	Coal Analysis
Manganese	2.58E-02	1.07E-01	Coal Analysis
Mercury	1.31E-02	4.68E-02	Coal Analysis
Molybdenum	3.23E-03	1.34E-02	Coal Analysis
Nickel	1.29E-02	5.35E-02	Coal Analysis
Selenium	3.23E-02	1.34E-01	Coal Analysis
Total Trace Metal HAPs		**0.48**	**tpy**

TABLE 3-5
Unit 1 Boiler Organic HAPs

Pollutant	Controlled Hourly Emissions (lb/hr)	Controlled Annual Emissions (tpy)	Emission Factor Reference
Biphenyl	4.14E-04	1.72E-03	AP-42, Table 1.1-13
Acenaphthene	1.24E-04	5.15E-04	AP-42, Table 1.1-13
Acenaphthylene	6.09E-05	2.52E-04	AP-42, Table 1.1-13
Anthracene	5.12E-05	2.12E-04	AP-42, Table 1.1-13
Benzo(a)anthracene	1.95E-05	8.08E-05	AP-42, Table 1.1-13
Benzo(a)pyrene	9.26E-06	3.84E-05	AP-42, Table 1.1-13
Benzo(b,j,k)fluoranthene	2.68E-05	1.11E-04	AP-42, Table 1.1-13
Benzo(g,h,i)perylene	6.58E-06	2.73E-05	AP-42, Table 1.1-13
Chrysene	2.44E-05	1.01E-04	AP-42, Table 1.1-13
Fluoranthene	1.73E-04	7.17E-04	AP-42, Table 1.1-13
Fluorene	2.22E-04	9.19E-04	AP-42, Table 1.1-13
Ideno(1,2,3-cd)pyrene	1.49E-05	6.16E-05	AP-42, Table 1.1-13
Naphthalene	3.17E-03	1.31E-02	AP-42, Table 1.1-13
Phenanthrene	6.58E-04	2.73E-03	AP-42, Table 1.1-13
Pyrene	8.04E-05	3.33E-04	AP-42, Table 1.1-13
5-Methyl chrysene	5.36E-06	2.22E-05	AP-42, Table 1.1-13
Total PAH	**5.06E-03**	**2.10E-02**	
Acetaldehyde	1.39E-01	5.76E-01	AP-42, Table 1.1-14
Acetophenone	3.65E-03	1.51E-02	AP-42, Table 1.1-14
Acrolein	7.07E-02	2.93E-01	AP-42, Table 1.1-14
Benzene	3.17E-01	1.31E+00	AP-42, Table 1.1-14
Benzyl chloride	1.71E-01	7.07E-01	AP-42, Table 1.1-14
Bis(2-ethylhexyl)phthalate	1.78E-02	7.37E-02	AP-42, Table 1.1-14
Bromoform	9.50E-03	3.94E-02	AP-42, Table 1.1-14
Carbon disulfide	3.17E-02	1.31E-01	AP-42, Table 1.1-14
2-Chloroacetophenone	1.71E-03	7.07E-03	AP-42, Table 1.1-14
Chlorobenzene	5.36E-03	2.22E-02	AP-42, Table 1.1-14
Chloroform	1.44E-02	5.96E-02	AP-42, Table 1.1-14
Cumene	1.29E-03	5.35E-03	AP-42, Table 1.1-14
~~Cyanide~~	~~6.09E-01~~	~~2.52E+00~~	~~AP-42, Table 1.1-14~~
2,4-Dinitrotoluene	6.82E-05	2.83E-04	AP-42, Table 1.1-14

TABLE 3-5
Unit 1 Boiler Organic HAPs

Pollutant	Controlled Hourly Emissions (lb/hr)	Controlled Annual Emissions (tpy)	Emission Factor Reference
Dimethyl sulfate	1.17E-02	4.85E-02	AP-42, Table 1.1-14
Ethyl benzene	2.29E-02	9.49E-02	AP-42, Table 1.1-14
Ethyl chloride	1.02E-02	4.24E-02	AP-42, Table 1.1-14
Ethylene dichloride	9.75E-03	4.04E-02	AP-42, Table 1.1-14
Ethylene dibromide	2.92E-04	1.21E-03	AP-42, Table 1.1-14
Formaldehyde	5.85E-02	2.42E-01	AP-42, Table 1.1-14
Hexane	1.63E-02	6.77E-02	AP-42, Table 1.1-14
Isophorone	1.41E-01	5.86E-01	AP-42, Table 1.1-14
Methyl bromide	3.90E-02	1.62E-01	AP-42, Table 1.1-14
Methyl chloride	1.29E-01	5.35E-01	AP-42, Table 1.1-14
Methyl ethyl ketone	9.50E-02	3.94E-01	AP-42, Table 1.1-14
Methyl hydrazine	4.14E-02	1.72E-01	AP-42, Table 1.1-14
Methyl methacrylate	4.87E-03	2.02E-02	AP-42, Table 1.1-14
Methyl tert butyl ether	8.53E-03	3.53E-02	AP-42, Table 1.1-14
Methylene chloride	7.07E-02	2.93E-01	AP-42, Table 1.1-14
Phenol	3.90E-03	1.62E-02	AP-42, Table 1.1-14
Propionaldehyde	9.26E-02	3.84E-01	AP-42, Table 1.1-14
Tetrachloroethylene	1.05E-02	4.34E-02	AP-42, Table 1.1-14
Toluene	5.85E-02	2.42E-01	AP-42, Table 1.1-14
1,1,1-Trichloroethane	4.87E-03	2.02E-02	AP-42, Table 1.1-14
Styrene	6.09E-03	2.52E-02	AP-42, Table 1.1-14
Xylenes	9.02E-03	3.74E-02	AP-42, Table 1.1-14
Vinyl acetate	1.85E-03	7.67E-03	AP-42, Table 1.1-14
Total Organics	**2.24E+00**	**9.28E+00**	

TABLE 3-6
Unit 1 Boiler Acid Gas HAPs

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)	Emission Factor Reference
Hydrogen Chloride	3.23	13.8	Engineering Estimates
Hydrogen Fluoride	2.62	11.2	Engineering Estimates
Total Acid Gas HAPs		**25.0**	**tpy**

3.3 Unit 1 Coal Handling

The estimated hourly and annual controlled particulate emission rates from the Unit 1 coal handling system are shown in Table 3-7. The tables summarize particulate emissions; details on each emission point can be found in Appendix B, entitled Emission Calculations. The annual emissions are based on 100 percent capacity factor. The emission sources will be equipped with fabric filter dust collectors to control particulate emissions.

TABLE 3-7
Unit 1 Coal Handling

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Emission Factor Reference
Total Particulate Matter	3.81	16.7	Dust Collector Grain Loading Method and Engineering Estimates
Particulate Matter PM_{10}	3.81	16.7	Dust Collector Grain Loading Method and Engineering Estimates

Includes Coal Storage Silos (ES1-07, ES1-08, ES1-09), Coal Crusher (ES1-10), and Plant Coal Transfer Bay Silo (ES1-11)

3.4 Unit 1 Lime Handling

The estimated hourly and annual controlled particulate emission rates from the Unit 1 lime handling system are shown in Table 3-8. The tables summarize particulate emissions; details on each emission point can be found in Appendix B, entitled Emission Calculations. The annual emissions are based on 100 percent capacity factor. The emission sources will be equipped with fabric filter dust collectors and/or bin vent filters to control particulate emissions.

TABLE 3-8
Unit 1 Lime Handling

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Emission Factor Reference
Total Particulate Matter	2.03	8.89	Dust Collector/Bin Vent Filter Grain Loading Method and Engineering Estimates
Particulate Matter PM_{10}	2.03	8.89	Dust Collector/Bin Vent Filter Grain Loading Method and Engineering Estimates

Includes Pebble Lime Receiving Silo (ES1-12), Pebble Lime Day Silo (ES1-13), Lime Hydrator Mixers (ES1-14, ES1-15), Hydrated Lime Crushers (ES1-16, ES1-17), and Hydrated Lime Silos (ES1-18, ES1-19)

3.5 Unit 1 Sorbent Injection System

The estimated hourly and annual controlled particulate emission rates from the Unit 1 sorbent injection system (if installed) are shown in Table 3-9. The annual emissions are based on 100 percent capacity factor. The emission source will be equipped with bin vent filters to control particulate emissions. Sorbent (activated carbon or another material) will be used to control mercury emissions from the Unit 1 boiler.

TABLE 3-9
Unit 1 Sorbent Injection System

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Emission Factor Reference
Total Particulate Matter	3.12E-02	1.37E-01	Bin Vent Filter Grain Loading Method and Engineering Estimates
Particulate Matter PM_{10}	3.12E-02	1.37E-01	Bin Vent Filter Grain Loading Method and Engineering Estimates

Includes Sorbent Silo (ES1-20)

3.6 Unit 1 Flyash/FGD Waste Handling and Hauling

The estimated hourly and annual controlled particulate emission rates from the Unit 1 flyash/FGD waste-handling systems are shown in Table 3-10. Flyash and FGD wastes are a combined product that is collected in the fabric filter hoppers following the FGD system. Both flyash and FGD waste are loaded "dry" into the silo from the fabric filter hoppers. The silos will be equipped with bin vent filters to reduce emissions. Water is added to reduce dust emissions when unloading the combined product from the silo into the trucks. The moisture content of the combined product unloaded into the trucks is 20 percent. The combined product is hauled on paved and unpaved roads to the landfill for disposal. Annual emissions are based on the annual flyash/FGD waste generated at 100 percent capacity factor for the main boiler.

TABLE 3-10
Unit 1 Fly Ash/FGD Waste Handling System

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Emission Factor Reference
Total Particulate Matter	3.17E-01	5.69E-01	Bin Vent Filter Grain Loading Method, WDEQ Emissions Guidance Document and Engineering Estimates
Particulate Matter PM_{10}	1.62E-01	4.34E-01	Bin Vent Filter Grain Loading Method, WDEQ Emissions Guidance Document and Engineering Estimates

Includes Fly Ash/FGD Waste Silo Separator/Filter Exhaust (ES1-21), Fly Ash/FGD Waste Silo Bin Vent Filter (ES1-22), Fly Ash/FGD Waste Loading into Trucks (FS1-01), Fly Ash/FGD Waste Disposal Paved Haul Road (FS1-02P), and Fly Ash/FGD Waste Disposal Unpaved Haul Road (FS1-02UP)

3.7 Unit 1 Bottom Ash Handling and Hauling

The estimated hourly and annual controlled particulate emission rates from the Unit 1 bottom ash handling systems are shown in Table 3-11. Bottom ash is removed from the boiler furnace by being quenched in water and then and transferred on a continuous basis to the bottom ash storage area using a drag chain conveyor. The storage area will have a concrete floor with concrete walls on three sides. Bottom ash dumped in the storage area will be loaded into haul trucks and taken to the landfill. The handling of the wet granulized bottom ash in the storage area will result in no emissions. Emissions will be generated by the haul trucks transferring material on paved and unpaved roads to the landfill. Annual emissions are based on the annual bottom ash generated at 100 percent capacity factor for the main boiler.

TABLE 3-11
Unit 1 Bottom Ash Handling System

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Emission Factor Reference
Total Particulate Matter	1.04E-02	2.28E-02	WDEQ Emissions Guidance Document and Engineering Estimates
Particulate Matter PM_{10}	3.13E-03	6.85E-03	WDEQ Emissions Guidance Document and Engineering Estimates

Includes Bottom Ash Disposal Paved Haul Road (FS1-04P) and Bottom Ash Disposal Unpaved Haul Road (FS1-04UP)

3.8 Fly Ash/FGD Waste Landfill

The estimated hourly and annual controlled particulate emission rates from the fly ash/FGD waste landfill are shown in Table 3-12. The table summarizes particulate emissions; details can be found in Appendix B. The sources for fugitive emissions include the dumping of fly ash/FGD waste material and bottom ash from the haul trucks onto the landfill; and maintenance of the landfill.

TABLE 3-12
Ash Landfill

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Emission Factor Reference
Total Particulate Matter	8.31E-01	1.79E+00	AP-42 and Engineering Estimates
Particulate Matter PM_{10}	2.02E-01	4.28E-01	AP-42 and Engineering Estimates

Includes Maintenance of Landfill (FS1-03a), Fly Ash/FGD Waste Dumping onto the Landfill from Haul Trucks (FS1-03c), and Bottom Ash Dumping onto the Landfill from Haul Trucks (FS1-03d)

3.9 Auxiliary Equipment

The auxiliary equipment at the Dry Fork Station will include an auxiliary boiler, diesel fire pump, emergency generator, inlet gas heater, and auxiliary cooling tower. Both the auxiliary boiler and inlet gas heater will be operated with natural gas. The fire pump and emergency generator will be diesel fuel operated.

3.9.1 Auxiliary Boiler

BEPC proposes to install a 134.1 MMBTU/hr natural gas operated auxiliary boiler. The hours of operation for the auxiliary boiler will not exceed 2,000 hours per year. Table 3-13 and Table 3-14 provide annual emissions for criteria pollutants and HAPs for the auxiliary boiler.

TABLE 3-13
Auxiliary Boiler Criteria Pollutants

Pollutant	Annual Emissions (tpy)	Emission Factor Reference
NO_X	7.24	Vendor Data and Engineering Estimates
CO	14.7	Vendor Data and Engineering Estimates
SO_2	7.89E-02	AP-42, Table 1.4-2
PM_{10}	1.00	AP-42, Table 1.4-2
VOC	0.72	AP-42, Table 1.4-2
Lead	6.57E-05	AP-42, Table 1.4-2

TABLE 3-14
Auxiliary Boiler HAPs

Pollutant	Annual Emissions (tpy)	Emission Factor Reference
Arsenic	2.63E-05	AP-42, Table 1.4-4
Beryllium	1.58E-06	AP-42, Table 1.4-4
Cadmium	1.45E-04	AP-42, Table 1.4-4
Chromium	1.84E-04	AP-42, Table 1.4-4
Cobalt	1.10E-05	AP-42, Table 1.4-4
Manganese	5.00E-05	AP-42, Table 1.4-4
Mercury	3.42E-05	AP-42, Table 1.4-4
Nickel	2.76E-04	AP-42, Table 1.4-4
Selenium	3.16E-06	AP-42, Table 1.4-4
Total Metal HAPs	**7.31E-04**	
2-Methylnaphthalene	3.16E-06	AP-42, Table 1.4-3
3-Methylchloranthrene	2.37E-07	AP-42, Table 1.4-3
7,12-Dimethylbenz(a)anthracene	2.10E-06	AP-42, Table 1.4-3
Acenaphthene	2.37E-07	AP-42, Table 1.4-3
Acenaphthylene	2.37E-07	AP-42, Table 1.4-3
Anthracene	3.16E-07	AP-42, Table 1.4-3
Benz(a)anthracene	2.37E-07	AP-42, Table 1.4-3
Benzene	2.76E-04	AP-42, Table 1.4-3
Benzo(a)pyrene	1.58E-07	AP-42, Table 1.4-3
Benzo(b)fluoranthene	2.37E-07	AP-42, Table 1.4-3
Benzo(g,h,i)perylene	1.58E-07	AP-42, Table 1.4-3
Benzo(k)fluoranthene	2.37E-07	AP-42, Table 1.4-3
Chrysene	2.37E-07	AP-42, Table 1.4-3
Dibenzo(a,h)anthracene	1.58E-07	AP-42, Table 1.4-3
Dichlorobenzene	1.58E-04	AP-42, Table 1.4-3
Fluoranthene	3.94E-07	AP-42, Table 1.4-3
Fluorene	3.68E-07	AP-42, Table 1.4-3
Formaldehyde	9.86E-03	AP-42, Table 1.4-3
Hexane	2.37E-01	AP-42, Table 1.4-3
Indeno(1,2,3-cd)pyrene	2.37E-07	AP-42, Table 1.4-3
Naphthalene	8.02E-05	AP-42, Table 1.4-3
Phenanathrene	2.24E-06	AP-42, Table 1.4-3
Pyrene	6.57E-07	AP-42, Table 1.4-3
Toluene	4.47E-04	AP-42, Table 1.4-3
Total Organic HAPs	**2.47E-01**	

3.9.2 Fire Pump

BEPC proposes to install a 360 HP diesel fuel operated fire pump. The expected hours of operation for the fire pump are 500 hours per year for periodic startup testing of the pump. Table 3-15 and Table 3-16 provide annual emissions for criteria pollutants and HAPs for the diesel fire pump.

TABLE 3-15
Fire Pump Criteria Pollutants

Pollutant	Annual Emissions (tpy)	Emission Factor Reference
NO$_x$	2.79E+00	AP-42, Table 3.3-1
CO	6.01E-01	AP-42, Table 3.3-1
SO$_2$	1.85E-01	AP-42, Table 3.3-1
PM$_{10}$	1.98E-01	AP-42, Table 3.3-1
VOC	2.26E-01	AP-42, Table 3.3-1

TABLE 3-16
Fire Pump HAPs

Pollutant	Annual Emissions (lb/yr)	Emission Factor Reference
Benzene	1.30E+00	AP-42, Table 3.3-2
Toluene	5.68E-01	AP-42, Table 3.3-2
Xylenes	3.96E-01	AP-42, Table 3.3-2
Propylene	3.59E+00	AP-42, Table 3.3-2
1,3-Butadiene	5.43E-02	AP-42, Table 3.3-2
Formaldehyde	1.64E+00	AP-42, Table 3.3-2
Acetaldehyde	1.07E+00	AP-42, Table 3.3-2
Acrolein	1.29E-01	AP-42, Table 3.3-2
Naphthalene	1.18E-01	AP-42, Table 3.3-2
Total HAPs	**8.85E+00**	**lb/yr**

3.9.3 Emergency Generator

BEPC proposes to install a 2,377 HP diesel fuel operated emergency generator. The estimated hours of operation for the generator are 500 hours per year for periodic startup testing of the emergency generator. Table 3-17 and Table 3-18 provide annual emissions for criteria pollutants and HAPs for the emergency generator.

TABLE 3-17
Generator Criteria Pollutants

Pollutant	Annual Emissions (tpy)	Emission Factor Reference
NO_x	1.43E+01	AP-42, Table 3.4-1
CO	3.27E+00	AP-42, Table 3.4-1
SO_2	2.40E-01	AP-42, Table 3.4-1
PM	4.16E-01	AP-42, Table 3.4-1
VOC	4.19E-01	AP-42, Table 3.4-1

TABLE 3-18
Generator HAPs

Pollutant	Annual Emissions (lb/yr)	Emission Factor Reference
Benzene	6.53E+00	AP-42, Table 3.4-3
Toluene	2.36E+00	AP-42, Table 3.4-3
Xylenes	1.62E+00	AP-42, Table 3.4-3
Formaldehyde	6.64E-01	AP-42, Table 3.4-3
Acetaldehyde	2.12E-01	AP-42, Table 3.4-3
Acrolein	6.63E-02	AP-42, Table 3.4-3
Naphthalene	1.09E+00	AP-42, Table 3.4-4
Total HAPs	**1.25E+01**	**lb/yr**

3.9.4 Inlet Gas Heater

BEPC proposes to install an 8.36 MMBTU/hr natural gas operated inlet gas heater. The hours of operation for the gas heater are estimated at 2,500 hours per year. Table 3-19 and Table 3-20 provide annual emissions for criteria pollutants and HAPs for the inlet gas heater.

TABLE 3-19
Inlet Gas Heater Criteria Pollutants

Pollutant	Annual Emissions (tpy)	Emission Factor Reference
NO_X	1.02	AP-42, Table 1.4-1
CO	0.86	AP-42, Table 1.4-1
SO_2	6.15E-03	AP-42, Table 1.4-2
PM_{10}	0.08	AP-42, Table 1.4-2
VOC	0.06	AP-42, Table 1.4-2
Lead	5.12E-06	AP-42, Table 1.4-2

TABLE 3-20
Inlet Gas Heater HAPs

Pollutant	Annual Emissions (tpy)	Emission Factor Reference
Arsenic	2.05E-06	AP-42, Table 1.4-4
Beryllium	1.23E-07	AP-42, Table 1.4-4
Cadmium	1.13E-05	AP-42, Table 1.4-4
Chromium	1.43E-05	AP-42, Table 1.4-4
Cobalt	8.61E-07	AP-42, Table 1.4-4
Manganese	3.89E-06	AP-42, Table 1.4-4
Mercury	2.66E-06	AP-42, Table 1.4-4
Nickel	2.15E-05	AP-42, Table 1.4-4
Selenium	2.46E-07	AP-42, Table 1.4-4
Total Metal HAPs	**5.70E-05**	**TPY**
2-Methylnaphthalene	2.46E-07	AP-42, Table 1.4-3
3-Methylchloranthrene	1.84E-08	AP-42, Table 1.4-3
7,12-Dimethylbenz(a)anthracene	1.64E-07	AP-42, Table 1.4-3
Acenaphthene	1.84E-08	AP-42, Table 1.4-3
Acenaphthylene	1.84E-08	AP-42, Table 1.4-3
Anthracene	2.46E-08	AP-42, Table 1.4-3
Benz(a)anthracene	1.84E-08	AP-42, Table 1.4-3
Benzene	2.15E-05	AP-42, Table 1.4-3
Benzo(a)pyrene	1.23E-08	AP-42, Table 1.4-3
Benzo(b)fluoranthene	1.84E-08	AP-42, Table 1.4-3

TABLE 3-20
Inlet Gas Heater HAPs

Pollutant	Annual Emissions (tpy)	Emission Factor Reference
Benzo(g,h,i)perylene	1.23E-08	AP-42, Table 1.4-3
Benzo(k)fluoranthene	1.84E-08	AP-42, Table 1.4-3
Chrysene	1.84E-08	AP-42, Table 1.4-3
Dibenzo(a,h)anthracene	1.23E-08	AP-42, Table 1.4-3
Dichlorobenzene	1.23E-05	AP-42, Table 1.4-3
Fluoranthene	3.07E-08	AP-42, Table 1.4-3
Fluorene	2.87E-08	AP-42, Table 1.4-3
Formaldehyde	7.68E-04	AP-42, Table 1.4-3
Hexane	1.84E-02	AP-42, Table 1.4-3
Indeno(1,2,3-cd)pyrene	1.84E-08	AP-42, Table 1.4-3
Naphthalene	6.25E-06	AP-42, Table 1.4-3
Phenanathrene	1.74E-07	AP-42, Table 1.4-3
Pyrene	5.12E-08	AP-42, Table 1.4-3
Toluene	3.48E-05	AP-42, Table 1.4-3
Total Organic HAPs	**1.93E-02**	**TPY**

3.9.5 Auxiliary Cooling Tower

Unit 1 will be equipped with a wet auxiliary cooling tower. The primary cooling tower related to the steam turbine will be an air cooled condenser (ACC) design and will not have any associated air emissions. The estimated annual controlled particulate emission rates from ES1-04, the wet auxiliary cooling tower, are shown in Table 3-21. The annual emissions are based on a 100 percent capacity factor.

TABLE 3-21
Unit 1 Wet Auxiliary Cooling Tower

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Emission Factor Reference
Total Particulate Matter	0.26	1.12	Engineering Estimates
Particulate Matter PM_{10}	0.06	0.27	Engineering Estimates

Section 4

Regulatory Review

SECTION 4.0

Regulatory Applicability Review and Requirements

This section provides a regulatory review of the applicability of state and federal air quality permitting requirements and air pollution control regulations for the Dry Fork Station Project proposed by BEPC. The purpose of this section is to provide appropriate explanation and rationale regarding the applicability of these regulations to the Dry Fork Station project. The review is divided into two major sections. The first section addresses state and federal air permitting requirements, and the second section addresses other state and federal air pollution control regulations.

4.1 Air Permitting Requirements

The State of Wyoming has approved authority to implement and enforce the federal Clean Air Act (CAA) pursuant to the state implementation plan (SIP) review and approval process. Federal Prevention of Significant Deterioration (PSD) air-permitting requirements are embodied within the state rules. The Dry Fork Station is a major emitting facility or major stationary source of air emissions, as defined within Wyoming Air Quality Standards and Regulations (WAQS&R) Chapter 6, Section 4.0 and 40 CFR 52.21.

4.1.1 State of Wyoming Air Permitting Requirements

The general requirements for permits and permit revisions are codified under the WAQS&R Chapter 6.

Construction Permit Application (Chapter 6, Section 2)

WAQS&R Chapter 6, Section 2.0 (1) (i) requires that a construction permit be obtained prior to commencing construction of a new or modified source of air emissions. WDEQ issues construction permits to commercial and industrial air pollution sources in Wyoming to ensure compliance with air quality regulations. The permitting process requires submission of forms provided by WDEQ. The application should include site information, plans, descriptions, specifications, and drawings showing the design of the source, the nature and amount of the emissions, and the manner in which it will be operated and controlled. A schedule for the construction or modification to the facility should also be included with the application.

The Dry Fork Station is located in an attainment area for all criteria pollutants. This construction permit application is being submitted to request issuance of a construction permit for the proposed project. Necessary application forms are also provided with this application.

Operating Permit Requirements (Chapter 6, Section 3)

The federal operating permits program (Title V) is implemented by regulations codified at 40 CFR Parts 70 and 71. The State of Wyoming has been granted authority to implement and enforce the federal Title V program through state regulations outlined under WAQS&R Chapter 6, Section 3.0.

An application for a Title V permit is required within 1 year of commencing operation of the proposed project, as specified in Chapter 6, Section 3.0 (c) (i), Timely Permit Application for Operating Permits. BEPC will submit a separate application for the Title V permit within 12 months after the startup of the Dry Fork Station project. Therefore, this document serves only as an application for the construction permit for the Dry Fork Station project, and it does not request a Title V permit.

PSD (Chapter 6, Section 4)

Within the federal NSR regulations, a subset of rules, which apply to major sources and major modifications within attainment areas, are referred to as the PSD program. Because the proposed Dry Fork Station will be located in an area classified as attainment for all criteria pollutants, the requirements of the federal PSD program will apply to the construction of the proposed project. The WDEQ has full authority to administer the federal PSD rules; consequently, these requirements are codified within the state permitting rules at WAQS&R Chapter 6, Section 4.0.

The PSD program defines a major stationary source as:

1. Any source type belonging to one of 28 listed source categories that has PTE of 100 tpy or more of any criteria pollutant regulated under the CAA, or
2. Any other (non-categorical) source type with a PTE of 250 tpy of any pollutant regulated under the CAA.

The Dry Fork Station belongs to one of the 28 listed source categories (fossil fuel-fired steam electric plants of more than 250 mmBtu/hr heat input) and has a PTE greater than 100 tpy for SO_2, NO_x, PM, PM_{10}, and CO.

The basic PSD permitting requirements that must be met for a major project include the following:

- Application of best available control technology (BACT) (presented in Section 5.0 of this application)
- Performance of an ambient air quality impacts analysis (dispersion modeling) (presented in Section 7.0 of this application)
- Analysis of impacts to soils, vegetation, and visibility (air quality-related values [AQRVs]) (presented in Sections 7.0 and 8.0 of this application)
- Analysis of Class I area impacts (presented in Section 8.0 of this application)

These requirements apply to attainment pollutants for which the project is major. The proposed project is a new major source (subject to the federal and state PSD program requirements) for NO_X, SO_2, CO, H_2SO_4, VOC, Fluorides as HF, Beryllium, PM andPM_{10}.

The Dry Fork Station is subject to the provisions in WAQS&R Chapter 6, Section 4.0 – Prevention of Significant Deterioration Program. Pursuant to this regulation, the Dry Fork Station is required to include the following information with the PSD permit application:

- Control Technology Review – Demonstration of application of Best Available Control Technology for Unit 1 for each regulated pollutant for which the emissions are significant. This review is in Section 5.0 of this application.
- Source Impact Analysis – An analysis of the PSD pollutants' air quality impact and a demonstration that the allowable emissions from the proposed project will not contribute to a violation of any NAAQS or PSD increment. This analysis is in Section 7.0 of this application.
- Additional Impact Analysis – An analysis of the PSD pollutants' air quality related impact including an analysis of the impairment to visibility, soils, and vegetation and the projected air quality impact from general commercial, residential, industrial, and other growth associated with the source. This analysis is contained in Sections 7.0 and 8.0 of this application.

Requirements Applicable to Nonattainment Areas (WAQS&R, Chapter 8)

The Dry Fork Station is located in an area classified as attainment; therefore, this rule does not apply.

Visibility (WAQS&R, Chapter 9)

This section describes the requirements for the WDEQ review of the proposed project for the impact of its PSD pollutant emissions on visibility in any mandatory Class I area. WDEQ is required to review the PSD pollutant emission impact analysis results to determine whether the proposed project will have an adverse impact on air quality-related values (including visibility). If the review determines that the PSD pollutants impact will be adverse, pre- or post-construction monitoring may be required for the facility.

Modeling results are provided in Section 8.0 of this application.

4.1.2 Federal Air Permit Requirements

Major Source NSR/PSD (40 CFR 51)

WDEQ has full authority to administer the federal PSD and NSR rules; therefore, these rules are summarized in 4.1.1.

Operating Permit Program (40 CFR Parts 70 and 71)

WDEQ has full authority for administering the federal Title V operating permit program rules; therefore, these rules are summarized in 4.1.1. The requirements of the federal program required under the 40CFR Part 71 do not apply to this project. A Title V operating permit under 40 CFR Part 70 will be applied for within 12 months after the startup of Unit 1.

Acid Rain Program (40 CFR Parts 72, 73, 75, 76, and 77)

As a PC-fired electric utility boiler, Unit 1 will be subject to the SO_2 allowance allocation, NO_X emission limitations, and monitoring provisions of the federal acid rain program. BEPC will apply for a acid rain permit for Unit 1. A CEMS will be designed, fabricated, installed, and certified on the new unit, in accordance with the requirements of 40 CFR 75. The State of Wyoming administers the acid rain program through Regulation 11, which is an adoption by reference of the federal code. See Section 9.0 for further details with regard to the federal CEMS requirements.

4.2 Other State and Federal Air Quality Requirements

4.2.1 Overview of State Air Quality Regulations

The following comments pertain to all air quality regulations contained in WAQS&R.

- The Common Provision Chapter 1 in WAQS&R are general in nature and do not provide specific standards, limitations, or other requirements applicable to the Dry Fork Station. However, they do govern other provisions in other articles of this chapter that pertain specifically to the plant now or possibly during future operations.
- The provisions of Chapter 2 in WAQS&R, pertain to ambient air quality standards. Compliance with these regulations must be demonstrated for obtaining a PSD permit for the Dry Fork Station and therefore these requirements apply to the Dry Fork Station.
- The provisions of Chapter 3 in WAQS&R, pertain to general emissions standard for particulate matter, nitrogen oxides, carbon monoxide, volatile organic compounds, sulfur oxides, and hydrogen sulfides; in general, these provisions apply to this facility.
- The provisions of Chapter 4 in WAQS&R, contain regulations for existing sulfuric acid production units, existing nitric acid manufacturing plants, existing municipal solid waste landfills, and existing hospital/medical/infectious was incinerators; these provisions do not apply.
- The provisions of Chapter 5 in WAQS&R, pertain to implementing federal NSPS and NESHAP Program. The provisions of 40 CFR 60 are incorporated by reference in Chapter 5, Section 2.0. These provisions apply to this facility.
- The provisions of Chapter 6 in WAQS&R, establish permitting requirement for all sources constructing and/or operating in the State of Wyoming; these provisions apply to this facility.
- The provisions of Chapter 7 in WAQS&R, establish general monitoring requirements; these provisions apply to this facility.
- The provisions of Chapter 8 in WAQS&R, contain regulations specific to sources operating in nonattainment areas; these provisions do not apply to this facility.
- The provisions of Chapter 9 in WAQS&R, contain regulations specific to visibility impacts in Class I areas; these provisions apply to this facility.

- The provisions of Chapter 10 in WAQS&R, establish restrictions and requirements on specific burning practices; these provisions do not apply to this facility.
- The provisions of Chapter 11 in WAQS&R, pertain to implementing federal Acid Rain Program. The provisions of 40 CFR 72 – 40 CFR 78 are incorporated by reference in Chapter 11, Section 2.0 and will apply to this facility.
- The provisions of Chapter 12 in WAQS&R, contain regulations designed to prevent the excessive build-up of air pollutants during air pollution episodes; in general, these provisions apply to this facility.
- The provisions of Chapter 13 in WAQS&R, establish minimum requirements for motor vehicle pollution control; these provisions do not apply to this facility.
- The provisions of Chapter 14 in WAQS&R, pertain to generic emission trading and banking. These regulations are general in nature and will not likely apply to the facility.

4.2.2 Other Federal Air Quality Regulations

NESHAPs (40 CFR Parts 61 and 63)

Requirements to receive authorization from the U.S. Environmental Protection Agency (EPA) (or delegated states) before construction or modification of a source are provided in 40 CFR 61.01 through 61.08. This application is being submitted pursuant to these paragraphs. The Dry Fork Station will also be a major emitter of hazardous air pollutants (HAPs) as defined in the Clean Air Act at 42 U.S. C. § 7412(g)(2).

The reporting and monitoring requirements applicable to the Auxiliary boiler and diesel generator are provided in 40 CFR 61.09 through 61.15. The remaining sections of 40 CFR 61 provide guidelines and requirements for specific sources that the Dry Fork Station does not operate; therefore, these sections do not apply to the Dry Fork Station in general.

Unit 1 is not subject to the *Industrial Commercial, and Institutional Boilers and Process Heater* NESHAP (40 CFR 60 Subpart DDDDD) per 40 CFR 63.7491(c). Unit 1 is an electric utility steam generating unit that is a fossil fuel fired combustion unit of more than 25 MW that serves a generator that produces electricity for sale therefore it is not subject to this subpart.

After a review of 40 CFR 60 Subpart DDDDD , the Auxiliary Boiler meets the criteria of an "affected" source as described in 40 CFR 63.7490. The Auxiliary boiler is considered a new large gaseous fuel boiler and is subject to the emission limitations, work practice standards, performance testing, monitoring, startup shutdown malfunction plan, and notification requirements. CO emissions from the unit are limited to 400 ppm by volume dry basis @ 3% O_2 on a 30 day rolling average. A performance test for CO emissions is required annually and CO CEMS must be installed as the unit is larger than 100 mmBtu/hr heat input.

The inlet gas heater is not subject to the emission limitations, work practice standards, performance testing, monitoring, startup shutdown malfunction plan, and notification requirements in 40 CFR 60 Subpart DDDDD. The unit is an affected source as defined in 40 CFR 63.7490 and is defined as a new small gaseous boiler or process heater (less than 10 mmBtu/hr heat input). Per 40 CFR 63.7506(c)(4), the affected boiler is not subject to the requirements of the subpart.

The diesel fire pump located at the Dry Fork Station does not meet the definition of an affected source per 40 CFR 63.6590(a) in 40 CFR 60 Subpart ZZZZ *Reciprocating Internal Combustion Engines (RICE)*. The unit is not an affected source because the site rated horsepower of the unit is less than 500 hp and the unit meets the definition of an emergency stationary RICE as its purpose is to pump water in case of fire therefore no emission or operating limitations are required.

The diesel emergency generator located at the Dry Fork Station is equipment meeting the criteria of an "affected" source as described in the regulation 40 CFR 63.6590(b) in subpart ZZZZ. An affected source is defined as a source with existing, new, or reconstructed stationary RICE with at site-rated horsepower greater than 500 hp located at a major source of HAP emissions. The RICE unit meets the definition of an emergency stationary RICE a as its purpose is to produce power when electrical power from the local utility is interrupted therefore no emission or operating limitations are required.

Dry Fork Station will comply with the newly promulgated mercury emission standard outlined in 40 CFR 60 Subpart Da, but is not subject to a requirement to perform a maximum achievable control technology (MACT) analysis for this or other HAPs.

Compliance Assurance Monitoring Program (40 CFR Part 64)

Because the proposed facility will be an "affected unit" subject to the federal acid rain program monitoring provisions, codified at 40 CFR Part 75, Dry Fork Station Unit 1 is exempt from the federal Compliance Assurance Monitoring (CAM) program requirements, codified at 40 CFR Part 64, for SO_2 and NO_X, pursuant to 40 CFR 64.2(b)(1)(iii). However, the unit will be subject to CAM requirements for SO_2 and NO_x with respect to Part 60 and WAQS&R permit limitations. The facility will also be subject to CAM requirements for particulates with respect to Part 60, Subparts Da and Y and WAQS&R permit limitations. The applicable CAM plans will be submitted with the Title V Operating Permit application that will be submitted to WDEQ within 12 months following initial startup.

NSPS (40 CFR Part 60)

These rules establish emissions limitations for SO_2, NO_X, PM and mercury and provide a variety of requirements for monitoring, recordkeeping, and reporting of emissions and other information. Any emissions unit subject to an NSPS subpart is also subject to the general provisions under Subpart A (codified at 40 CFR 60.1 through 60.19). The Dry Fork Station will also be subject to the provisions in Appendices B and F of this subpart, which outline requirements and specifications for continuous opacity monitoring systems (COMS), CEMS, and the quality assurance (QA) and quality control (QC) plans required for these monitoring systems. The content of these sections is extremely detailed. Guidance regarding SIPs is given in sections 40 CFR 60.20 through 60.29 (Subpart B); these sections do not apply to the Dry Fork Station.

Sections 40 CFR 60.30 through 60.39 (Subpart C) are specific to waste combustion units, incinerators, solid waste landfills, and sulfuric acid production plants. Dry Fork Station does not conduct any of these processes; therefore, the requirements in this section do not apply to the Dry Fork Station facility.

The provisions of 40 CFR 60.40 through 60.49 (Subpart D) apply to fossil fuel-fired steam boilers having a heat input of 250 mmBtu per hour or more, and constructed since August 17, 1971. The Dry Fork Station Unit 1 fits this definition; however, similar electric utility units constructed after September 18, 1978, are subject to the requirements of NSPS Subpart Da (see next paragraph) which, for such units, supercedes Subpart D.

The provisions of 40 CFR 60.40a through 60.52a (Subpart Da) apply to electric utility steam generating units having a heat input of 250 mmBtu/hour or more and constructed on or after September 18, 1978. The proposed Unit 1 will be a maximum 422 gross MW PC-fired electric utility steam boiler rated in excess of 250 MMBtu per hour heat input and is therefore subject to the requirements of 40 CFR Subpart Da. According to this subpart, all monitoring activities and reports of emissions should be documented and retained on file, and the following may not be exceeded:

- PM 0.03 lb/mmBtu (§ 60.42a) 30-day rolling average
- Opacity of 20 percent, except for one 6-minute period per hour (§ 60.42a)
- SO_2 1.2 lb/mmBtu (§ 60.43a) 30-day rolling average
- 70 percent reduction of SO_2 because emissions are less than 0.60 lb/mmBtu) (§ 60.43a) 30-day rolling average for emission limit and 24 hour average for percent removal.
- NO_X 1.6 pounds per megawatt hour (MWH)(§ 60.44a d 1) 30-day rolling average
- Mercury 78 x 10^{-6} lb/MWh on an output basis (§ 60.45a a 1) 12-month rolling average since the Dry Fork Station will utilize only subbituminous coal

COMS and SO_2, NO_X and mercury CEMS must be installed, calibrated, maintained, operated, and recorded in accordance with the requirements in 40 CFR 60.47a through 60.51a. A PM CEMS is not required. Documentation is required to be maintained regarding performance tests, calibration, and maintenance of the equipment. These monitoring systems shall be certified in accordance with the performance specifications provided in Appendix B to Part 60 and maintained in accordance with the QA requirements provided in Appendix G to Part 60. Note that some of the criteria and certification test requirements within these NSPS appendices are, for acid rain sources, superceded by certain provisions within 40 CFR Part 75, which was promulgated later.

The auxiliary boiler that will be used for heating and warm-up is subject to the NSPS for steam generating units with a heat input capacity of greater than 100 MmBtu/hr but less than 250 mmBtu/hr (40 CFR 60, Subpart Db). However, most of the requirements of this subpart apply only to oil- and coal-burning units. The nominal 134.1 mmBtu/hr boiler proposed for the project will use pipeline quality natural gas only with no backup fuel. Therefore, only 40 CFR 60.44b, 60.46b, 60.48b and 60.49b are applicable.

For 40 CFR 60 Subpart Y, Standard of Performance for Coal Preparation Plants applies to new coal-handling units that are constructed after October 24, 1974. A coal-handling system is included for Unit 1. The coal-handling system is subject to NSPS Subpart Y. The affected facilities that are subject to NSPS Subpart Y include the coal handling facilities from the crusher and conveyor into the bunkers at the boiler. Exempt from Subpart Y are the coal-handling facilities from the emergency truck dump.

Accidental Release Program – (40 CFR 68)

Section 112 (r) of the Clean Air Act and 40 CFR 68 require sources to develop a Risk Management Plan (RMP) for any chemicals stored onsite above threshold quantities defined in 40 CFR 68. BEPC plans to use anhydrous ammonia in quantities above the threshold, thus an RMP will be required.

Acid Rain Provisions (40 CFR Parts 72, 73, 75, 76, 77 and 78)

The Acid Rain Deposition Control Program is implemented by the Environmental Protection Agency (EPA), with Phase II administered by the states. Dry Fork Station Unit 1 is an affected unit under the Acid Rain Program, which is governed by 40 CFR Parts 72, 73, 75, 76, 77, and 78. The facility will, therefore, be subject to Phase II of the acid rain program pursuant to Title IV of the CAA and will be required to submit a complete and timely Title IV permit application. The facility will be required to obtain allowances for calendar-year SO_2 emissions. These allowances are expected to be readily available on the open-market trading system. Additionally, the Title IV permit will require emissions monitoring for NO_X and fuel monitoring for sulfur content.

4.2.3 Regulatory Applicability Summary Matrix

Appendices C and D contain tables that summarizes all the Wyoming and Federal applicable requirements. The tables identify all requirements, denote applicability, provide explanations, and compliance methods used if applicable.

Section 5

Control Technology

SECTION 5.0

Control Technology Analysis

This section describes the air pollution control equipment that will be utilized on the proposed Dry Fork power plant project, the best available control technology (BACT) analysis for applicable pollutants, the discussion of how the plant will comply with the Clean Air Mercury Rule (CAMR) and the maximum achievable control technology (MACT) demonstration for hazardous air pollutant emissions from the auxiliary boiler.

Basin Electric selected a pulverized coal (PC) boiler design for this project. EPA has not considered the BACT requirement as a means to redefine the design of the source, although some states have chosen to engage in a broader analysis. Therefore, this BACT analysis does not evaluate different combustion designs such as circulating fluidized bed (CFB) or integrated gasification combined cycle (IGCC) since these combustion processes are fundamentally different from the chosen PC boiler design.

Emissions from the Dry Fork Station will exceed PSD significant annual emission rates and will therefore be subject to a best available control technology (BACT) review for carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), volatile organic compounds (VOC), sulfur dioxide (SO_2), nitrogen oxides (NO_x), sulfuric acid mist (H_2SO_4), beryllium (Be), and fluorides (as HF).

5.1 Pollution Controls

The proposed Dry Fork Station will be equipped with advanced pollution controls to limit the emissions of SO_2, sulfuric acid mist, HCl, fluorides as HF, NO_x, PM, PM_{10}, lead, and beryllium.

5.1.1 Sulfur Dioxide and Related Compounds

Emissions of sulfur dioxide and sulfuric acid mist will be controlled on Dry Fork to BACT levels with the use of a dry lime scrubbing flue gas desulfurization (FGD) system. The FGD system will have a design outlet SO_2 emission rate of 0.10 lb/mmBtu, which corresponds to an SO_2 removal efficiency of 91.7 percent at the design maximum coal sulfur content of 0.47 wt. percent. The dry FGD system will also remove at least 90 percent of the sulfuric acid mist.

There will be no total reduced sulfur (TRS) and reduced sulfur compound (RSC) emissions from the boiler because utility coal-fired boilers are operated with approximately 20 percent excess air to insure complete combustion and oxidation of sulfur in the coal to SO_2 and SO_3. This insures there are no reduced sulfur species in the flue gas exiting the chimney.

Reduced sulfur species could only be formed where oxygen poor substoichiometric combustion occurs. By design, low-NO_x burners create a small substoichiometric combustion zone at the burner to reduce NO_x formation followed by an overfire air zone to allow for the completion of combustion of the fuel. While NO_x reduction is achieved with this staged combustion approach, the substoichiometric combustion mechanism also generates some amount of hydrogen sulfide (H_2S) in the flue gases at the vicinity of the burner. However, any H_2S that may have formed is later totally oxidized to SO_2 and SO_3 by further combustion in the overfire excess air which is injected directly above the reducing zone of the boiler. A new pulverized coal boiler, with low-NO_x burners and overfire air, would be instrumented and operated using a distributed control system (DCS) that would insure sufficient oxygen to achieve complete combustion of the fuel and oxidation of any reduced sulfur species formed in the lower combustion zone.

Dry lime scrubbing technology is generally used for low-sulfur coal. Dry FGD processes are typically located after the air preheater, and the waste products are collected in a baghouse or electrostatic precipitator (ESP). Several variations on the dry FGD technology are offered by various process developers. These variations include the lime spray drying, circulating dry scrubbing (CDS) and lime flash drying processes.

In a lime spray drying FGD system, lime (calcium oxide) reagent is slaked with water to form calcium hydroxide slurry. The slurry contacts the flue gas when it is sprayed as finely atomized droplets through a rapidly spinning atomizing wheel into a spray dryer vessel. The spray dryer vessel will be installed in the flue gas ductwork upstream of a baghouse. The flue gas temperature leaving the spray dryer vessel is maintained approximately 35°F above the adiabatic approach to the saturation point. This allows carbon steel construction of the spray dryer vessel.

The spray dryer vessel has sufficient residence time (approximately 10 seconds) to allow the SO_2 in the flue gas to react with the reagent as the water in the slurry droplets evaporates, forming a dry calcium sulfite and calcium sulfate byproduct. This dry byproduct, along with remaining fly ash, is collected in the bottom of the spray dryer vessel and in the downstream baghouse. A portion of the collected dry solids will be re-slurried and re-injected into the spray dryer to improve reagent utilization.

A CDS dry FGD system uses hydrated lime as a reagent. Preparation of the hydrated lime involves an atmospheric lime hydrator. The hydrated lime is stored in a day silo for later use. The hydrated lime is fed to the absorber by means of a rotary screw feeder or a gravimetric feeder may be evaluated for more consistent control. The reagent is fed to the absorber to replenish hydrated lime consumed in the reaction, and the feed rate is typically controlled based on the required removal efficiency.

The waste product from a dry FGD system contains $CaSO_3$, $CaSO_4$, calcium hydroxide, calcium carbonate, and ash. The collected dry solids will be pneumatically conveyed to a storage silo and trucked back to the coal mine for landfill disposal. The dry FGD system for Dry Fork will be designed to meet the SO_2 emission levels described in Section 3 (Emissions Summary) and Section 6 (Requested Permit Limits).

5.1.2 Hydrochloric Acid and Hydrogen Fluoride

The use of the dry flue gas desulfurization system on Dry Fork will also reduce HCl and HF potential emissions by at least 90 percent. Based on operating data at other similar coal-fired ~~utilities and municipal waste combustors (MWC) that utilize combination CDS or lime~~ spray dryer and fabric filter control systems, very high acid gas removal efficiencies have been demonstrated. Removal efficiencies up to 98 to 99 percent for HCl and for HF have been reported, however, these high control efficiencies have been demonstrated on flue gas streams with high HCl and HF concentrations, and not on coal-fired utility boilers with significantly large flue gas flow rates and lower HCl and HF concentrations such as Dry Fork. The level of control is also dependent on the coal properties. Some of the HCl and HF removal occurs in the dry FGD absorber vessel itself due to the reaction with the hydrated lime. Removal also takes place as a result of the flue gas humidification in the absorber and the collection of the reagent and flyash product on the fabric filter bags.

5.1.3 Nitrogen Oxides

NO_x is formed in the boiler in the combustion process, particularly when the peak combustion temperature in the flame exceeds 2,500°F. The emissions of NO_x from Dry Fork will be controlled to BACT levels through the use of Low NO_x Burners (LNB) with Overfire Air and Selective Catalytic Reduction (SCR). Low NO_x burners control the formation of NO_x by staging the combustion of the coal to keep the peak flame temperature below the threshold needed for NO_x formation. The burner initially introduces the coal into the boiler with less air than is needed for complete combustion. The flame is then directed toward an area where additional combustion air is introduced from over-fire air ports allowing final combustion of the fuel.

A selective catalytic reduction unit will also be installed on Dry Fork to further reduce the NO_x emissions. The proposed SCR is designed for high dust loading applications and will be located external from the boiler. The SCR system uses a catalyst and a reductant (ammonia gas, NH_3) to dissociate NO_x into nitrogen gas and water vapor. The catalytic process reactions for this NO_x removal are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O, \text{ and}$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O.$$

The optimum temperature window for this catalytic reaction is between approximately 575 and 750°F. Therefore, the SCR reaction chamber will be located between the boiler economizer outlet and air heater flue-gas inlet. The system will be designed to use ammonia as the reducing agent. Anhydrous ammonia will be transported by truck and stored onsite. Gaseous ammonia will be injected into Unit 1 through injection pipes, nozzles, and a mixing grid that will be located upstream of the SCR reaction chamber. A diluted mixture of ammonia gas in air will be dispersed through injection nozzles into the flue-gas stream. The ammonia/flue-gas mixture then enters the reactor where the catalytic reaction occurs.

Based on technical information provided by the boiler vendor, it is anticipated that NO_x emissions from the boiler (prior to the SCR) can be controlled by LNBs with Overfire Air to 0.20 to 0.25 lb/mmBtu while maintaining acceptable levels of CO and VOC. The SCR system will have a design NO_x emission rate of 0.07 lb/mmBtu, which corresponds to an SCR NO_x removal efficiency of 72 percent based on a 0.25 lb/mmBtu NOx inlet.

5.1.4 Particulate Matter and PM_{10}

Particulate matter (PM) and particulate matter smaller than 10 micrometers diameter (PM_{10}) ~~will be controlled at Dry Fork by a fabric filter. The fabric filters operate by passing the~~ particle-laden flue gas through a series of felted fabric bags. The bags accumulate a filter cake that removes the particles from the flue gas, and the cleaned flue gas passes out of the fabric filter. The fabric filters will have a particulate removal efficiency of greater than 99 percent.

The fabric filter system will consist of a number of parallel banks of individual filter compartments located downstream of the air preheaters and the flue gas desulfurization system and upstream of the induced draft fans. Individual filter compartments consist of a bottom collection hopper, a collector housing, and an upper plenum. A group of cylindrical filter bags, each covering a cylindrical wire cage retainer, hang from a tubesheet, which separates the upper plenum from the collector housing.

Particle-laden flue gas from the boiler enters the collector housing, just above the bottom collection hopper. The flue gas stream travels up through the collector housing where particles collect on the outside of the cylindrical filter bags. The filtered flue gas then travels up through the inside of the cylindrical filter bags, through the tubesheet, and out through the upper plenum. Particulate matter captured on the filter bags will form a filter cake. The filter cake increases both the filtration efficiency of the cloth and its resistance to gas flow.

Fabric filtration is a constant-emission device. Pressure drop across the filters, inlet particulate loading, or changes in gas volumes may change the rate of filter cake buildup, but will not change the final emission rate. Actual performance of a fabric filter depends on specific items, such as air/cloth ratio, permeability of the filter cake, the loading and nature of the particulate material (e.g., irregular-shaped or spherical), and particle size distribution.

The filter bags must be cleaned periodically to remove accumulated filter cake. The cleaning frequency of the individual compartments will depend, in part, on the inlet grain loading and the flow resistance of the filter cake formed. It is anticipated that the fabric filter system will be designed as a pulse jet-type system. In a pulse jet-type system, gas flow through an isolated compartment is stopped and pulses of compressed air are blown down into the inside of each bag causing the filter bag to puff outward, fracturing and dislodging the accumulated filter cake. The filter cake falls into the collection hopper for transport to the flyash-handling system.

The fabric filter system design involves inlet particulate matter loading rates, flyash characteristics, the selection of the cleaning mechanism, and selection of a suitable bag filter fabric and finish.

5.1.5 Beryllium and Lead

The use of a fabric filter and dry lime FGD system on Dry Fork will reduce potential beryllium and lead emissions by 99 percent. Beryllium and lead are emitted as trace metal constituents in the flyash leaving the boiler. The removal of beryllium and lead correlates with the collection efficiency of the particulate removal device. Because the fabric filter will remove greater than 99 percent of the total particulate matter, the removal efficiency of beryllium and lead will be similar. A fabric filter preceded by a dry lime FGD system is selected as the control technology of beryllium and lead emissions for this project.

5.1.6 Carbon Monoxide and Volatile Organic Compounds

Carbon monoxide (CO) and non-methane volatile organic compounds (VOCs) are formed from the incomplete combustion of the coal in the boiler. The formation of CO and VOCs is limited by controlling the combustion of the fuel and providing adequate oxygen for complete combustion. Thus, good combustion control is the technique to be used to limit CO and VOC emissions.

5.2 BACT Determination

This section presents the required BACT analyses.

5.2.1 Applicability

The requirement to conduct a BACT analysis and determination is set forth in section 165(a)(4) of the Clean Air Act and in federal regulations 40 CFR 52.21(j).

5.2.2 Top-Down BACT Process

EPA has developed a process for conducting BACT analyses. This method is referred to as the "top-down" method. The steps to conducting a "top-down" analysis are listed in EPA's "New Source Review Workshop Manual," Draft, October 1990. The steps are the following:

- Step 1 – Identify All Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Controls and Document Results
- Step 5 – Select BACT

Each of these steps has been conducted for SO_2, H_2SO_4, NOx, CO, VOC, PM, PM_{10}, fluoride and beryllium and are described below.

5.2.3 SO_2 and H_2SO_4 Analysis

The BACT analysis for sulfur dioxide is presented below. The analysis is also applicable to sulfuric acid mist (H_2SO_4).

Step 1 – Identify All Control Technologies

Sulfur dioxide (SO_2) will be emitted from the proposed Dry Fork Station as a result of the combustion of coal that contains sulfur. The first step is to evaluate SO_2 controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RACT/BACT/LAER Clearinghouse (RBLC) database accessible on the Internet. The printout from the database for SO_2 is shown in Appendix E, Table E-7. The printout from the database for H_2SO_4 is shown in Appendix E, Table E-9. A broad range of other information sources were also reviewed in an effort to identify all potentially applicable emission control technologies.

The potential SO_2 emission reduction options found in the RBLC and other sources that could be applied to the Dry Fork Station are:

- Wet lime/limestone scrubbing
- Dry lime scrubbing

The control efficiencies for these technologies range from 73 percent to 95 percent. However, with the exception of two projects in Wyoming using a circulating dry lime scrubber and one project in Wyoming using a lime spray dryer, the reported removal rates are 90 percent to 95 percent. FGD control efficiencies will be in the lower end of this range when used with low sulfur coal.

Step 2 – Eliminate Technically Infeasible Options

Both of these options are technically feasible for use in reducing SO_2 emissions from the Dry Fork Station. Control efficiencies for circulating dry scrubbers (CDS) have not been demonstrated above 80 percent in the RBLC database. However, this technology has demonstrated SO_2 removal efficiencies above 90 percent in European installations. For this reason this technology was included for further consideration.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for each of the SO_2 removal technologies are ranked in order of their control effectiveness. These effectiveness values are provided in Table 5-1. The PSD NSR regulations require that BACT, at a minimum, meet the applicable NSPS limit, 40 CFR 60 Subpart Da. Because there is an NSPS that applies to the boiler, the NSPS emission limit is also included in the ranking.

TABLE 5-1
SO_2 Control Technology Emission Rate Ranking

Control Technology	SO_2 Emission Rate [a]
Wet Limestone Scrubbing	0.09 – 0.40
Circulating Dry Scrubber	0.10 – 0.32
Lime Spray Dryer	0.10 – 0.32
Wet Lime Scrubbing	0.13 – 0.25
NSPS Limit	0.34[b]

[a] Pounds per million BTU as found in the RBLC database and recently approved PSD permits.
[b] Based on an uncontrolled SO_2 emission rate of 1.12 Lb/MmBtu and a removal efficiency of 70 percent, which is the applicable standard under NSPS subpart Da when SO_2 emissions are less than 0.60 pounds per MmBtu.

Nomenclature:

NSPS = New Source Performance Standards

Step 4 – Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology.

Wet Limestone/Lime FGD

~~Wet SO_2 scrubbers operate by flowing the flue gas upward through a large reactor vessel~~ that has an alkaline reagent (i.e. limestone or lime slurry) flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel. The calcium in the reagent reacts with the SO_2 in the flue gas to form calcium sulfite and/or calcium sulfate that is removed from the scrubber with the sludge and is disposed. Most wet FGD systems utilize forced oxidation to assure that only calcium sulfate sludge is produced. The wet limestone forced oxidation (LSFO) process is used in most new wet FGD installations. Several variations on the wet FGD technology are offered by various process developers. These variations include using a jet bubbling reactor as a combination SO_2 absorber and calcium sulfite oxidation vessel, and using magnesium enhanced lime as the alkaline reagent.

The creation of a wet sludge from the scrubber does create a solid waste handling and disposal problem. This sludge needs to be handled in a manner to not result in ground water contamination. Also, the sludge disposal area needs to be permanently set aside from future surface uses since the disposed sludge can not bear any weight from such uses as buildings or cultivated agriculture. Wet FGD systems can produce salable gypsum if a gypsum market is available, reducing the quantity of solid waste that needs to be disposed of from the power plant.

Other disadvantages associated with wet limestone or lime FGD includes the creation of a wet stack plume, generation of primary particulate matter by the scrubbing process, increased acid gas emissions, incompatibility with mercury removal options and water/wastewater issues. Wet FGD generates more primary particulate emissions leaving the stack than dry FGD systems because the particulate removal device (ESP or Fabric Filter) is upstream of the scrubber instead of downstream as in this case. Sulfuric acid removal for a wet FGD system is in the range of 40 to 60 percent compared to 90 percent for a dry lime absorber/fabric filter combination. The potential future use of activated carbon or sorbent injection for mercury removal is also limited with a wet FGD application since the fabric filter is upstream of the scrubber and the flue gas temperature is higher than the optimum mercury capture range.

Wet FGD also requires more makeup water than Dry FGD, and typically requires a wastewater blowdown stream that must be treated to limit the buildup of chlorides in the absorber scrubbing loop. Given that the amount of water available for the Dry Fork Station is quite limited to the point of requiring dry cooling for much of its heat dissipation, the increased water consumption required for the wet scrubber is a serious concern.

Dry Lime FGD Absorber Followed by Fabric Filter

In CDS and lime spray dryer systems, SO_2 reacts with lime in an absorber vessel. The CDS absorber operates as a circulating fluidized bed of hydrated lime, reaction products and ash. The flue gas is humidified at the venturi inlet in the bottom of the fluidized bed. Dry hydrated lime and recycle solids are injected above the venturi. The hydrated lime reacts with the SO_2 in the flue gas reacts to form particulate calcium sulfate. This dry material is captured in the fabric filter along with the fly ash.

The lime spray dryer typically injects lime slurry in the top of the vessel with a rapidly rotating atomizer wheel. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas where the SO_2 in the flue gas ~~reacts with the calcium in the lime slurry to form particulate calcium sulfate. This dry~~ material is captured in the fabric filter along with the fly ash.

The CDS and lime spray dryer FGD systems produce a dry waste product suitable for landfill disposal.

CDS and lime spray dryer systems are in operation at many facilities in Europe, China and the U.S. ranging in size from less than 10 MW to 350 MW. CDS and lime spray dryer FGD are commercially available from multiple process developers/vendors.

The dry FGD systems have a number of advantages when compared to wet FGD technology. The absorber vessel can be constructed of unlined carbon steel, as opposed to lined carbon steel or solid alloy construction for wet FGD, and the capital cost is typically lower than for wet FGD.

The pressure drop across the absorber is typically lower than wet FGD systems. Pumping requirements and overall power consumption are lower than for wet FGD systems. The dry FGD systems use less equipment than does the wet FGD system, resulting in fixed, lower operations and maintenance (O&M) labor requirements.

Sulfur trioxide (SO_3) in the vapor above approximately 300°F, which condenses to liquid sulfuric acid at a lower temperature (below acid dew point), is removed efficiently with a CDS or lime spray dryer system. Wet scrubbers capture less than 40 to 60 percent of SO_3 and may require the addition of a wet ESP, or hydrated lime injection, to remove the balance of SO_3. Otherwise, the emission of sulfuric acid mist, if above a threshold value, may result in a visible plume after the vapor plume dissipates.

Flue gas following a dry FGD system is not saturated with water (30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet FGD scrubbers produce flue gas that is saturated with water, which would require a gas-gas heat exchanger to reheat the flue gas if it were to operate as a dry stack. Due to the high capital and operating costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operation.

Waste produced is in a dry form and can be handled with conventional pneumatic fly ash handling equipment. The waste is stable for landfill purposes and can be disposed of concurrently with fly ash.

There is no liquid waste from a dry FGD system, while wet FGD systems may produce a liquid waste stream, especially if the gypsum is to be sold for wallboard. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant produces a small volume of solid waste, which may be contaminated with toxic metals (including mercury) that must be disposed of in a landfill. The humidification stream of a CDS system provides a way to achieve a dry by-product from process wastewater from other parts of the plant when processing residue for disposal.

Dry FGD technology has only a few disadvantages when compared to wet FGD technology. The dry FGD process uses a more expensive reagent (hydrated lime) than limestone-based FGD systems, and the reagent has to be stored in a steel or concrete silo. Reagent utilization is lower than for wet limestone systems to achieve comparable SO_2 removal. The lime stoichiometric ratio is higher than the limestone stoichiometric ratio (on the same basis) to achieve comparable SO_2 removal.

The CDS process is applicable mostly for base-load applications such as at the Dry Fork Station, as high velocities are required to maintain the bed in suspension. The standard design includes provisions for ID fan recycle to keep the gas velocity high in the CDS vessel to mitigate this shortcoming.

Since dry FGD is being proposed for this project, the environmental, energy and economic impacts must be examined. Sargent & Lundy, the Engineer for the Dry Fork project, developed cost estimates for a dry lime FGD and for a wet limestone FGD installation and operation. The average cost effectiveness of a dry lime FGD system designed to achieve a controlled SO_2 emission rate of 0.10 lb/mmBtu (87.8 percent SO_2 removal efficiency based on 0.33 wt. percent average coal sulfur content) was estimated at $1,248 per ton of SO_2 controlled. The average cost effectiveness of the wet scrubbing system designed to achieve a controlled SO2 emission rate of 0.09 lb/mmBtu (89.0 percent SO2 removal efficiency based on 0.33 wt. percent average coal sulfur content) was estimated to be $1,450 per ton of SO2 controlled.

Based on average cost effectiveness calculations, both wet and dry FGD systems appear to be cost effective. An incremental cost analysis was also prepared to evaluate the incremental cost effectiveness of the wet scrubbing system. The incremental cost effectiveness of the wet limestone FGD (compared to the dry lime FGD) was calculated at $13,157 per additional ton of SO_2. The incremental cost effectiveness reflects the additional capital, O&M, and fabric filter costs associated with the wet FGD system.

With a wet FGD design, the fabric filter would be prior to the FGD system, and the resultant capital and operating costs are higher than a similar fabric filter that follows a dry lime FGD system. A comparison of the costs and SO_2 removed is summarized in Table 5-2. The annualized cost estimate for a wet lime system would be similar to the one prepared for wet limestone with the primary difference being the higher cost of lime reagent. Because wet limestone FGD has a similar removal efficiency to wet lime FGD and the operating costs are lower, it was decided that wet limestone FGD was the appropriate cost comparison alternative to the dry lime FGD system.

Dry FGD has the advantages of producing a dry waste material and requiring less makeup water in the absorber over a wet scrubber. Given that the amount of water available for Dry Fork is quite limited to the point of requiring dry cooling for much of its heat dissipation, the reduced water consumption required for dry FGD is major advantage for this technology.

A Dry FGD system has the additional advantage of requiring less electric power for its operation compared to a Wet FGD system. A dry FGD system at Dry Fork would require approximately 2.8 MW of power compared to approximately 5.3 MW for Wet FGD. This would equate to an annual power savings of approximately 18.6 million kW-Hr for dry FGD versus wet FGD for Dry Fork based on an 85 percent annual plant capacity factor. Instead of this amount of power being used in the power plant, this power can instead be sold to Basin Electric's customers reducing the need to produce this power elsewhere.

TABLE 5-2
Dry Form SO_2 Control Cost Comparison

Factor	Dry Lime FGD	Wet Limestone FGD
Total Installed Capital Costs	$ 63.6 Million	$ 77.4 Million
Total Fixed & Variable O&M Costs	$ 4.4 Million	$ 4.8 Million
Total Annualized Cost	$ 15.0 Million	$ 17.6 Million
FGD Design Control Efficiency	87.8 percent	89.0 percent
Tons SO_2 Removed per Year	11,980	12,144
Cost Effectiveness per Ton of SO_2 Removed	$ 1,248	$ 1,450
Incremental Annualized Cost Difference between Wet LSFO FGD and dry lime FGD	-	$ 2.6 Million
Incremental Tons SO_2 Removed between Wet LSFO FGD and dry lime FGD	-	202
Incremental Cost Effectiveness per Ton of Additional SO_2 Removed by Wet LSFO FGD	-	$ 13,157

Basin Electric believes that the high additional cost of wet limestone/lime scrubbing is not warranted for this project based on the use of low sulfur coal and the limited additional tons of SO_2 removed. Wet FGD also has the disadvantages of waste disposal of a wet FGD sludge, increased water consumption requirements, possible future complications with mercury removal, higher particulate emissions and the fact that dry FGD can meet a SO_2 emission limit that is comparable to BACT as determined in other recent permits listed in the RBLC database.

Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. EPA's RACT/BACT/LAER Clearinghouse (RBLC), a database of past technology decisions, and recently approved PSD permits were again consulted to assist in selecting BACT for this project.

Both dry FGD and wet limestone scrubbing have been demonstrated at removal efficiencies greater than 90 percent. The installation of a dry FGD system on Dry Fork will result in a SO_2 removal efficiency of 91.7 percent for the design maximum coal sulfur content of 0.47 wt. percent. The highest collection efficiency shown in the RBLC is 95 percent on Santee Cooper Cross Unit No. 1, however, this unit burns high sulfur coal.

The recent addition of the 750-net MW MidAmerican Council Bluffs Energy Center (CBEC) Unit 4, which is under construction, was permitted at 0.10 lb/mmBtu (30-day rolling average) based on the use of low sulfur PRB coal and a lime spray dryer FGD. The design SO_2 emission rate for Dry Fork is 0.10 lb/mmBtu which is identical to the CBEC Unit 4 design SO_2 emission rate, and consistent with the low end of the range of emissions for units in the RBLC.

The 950-gross MW Intermountain Power Project (IPP) Unit 3 was recently permitted at 0.09 lb/mmBtu (30-day rolling average) based on the use of western bituminous coal and a wet limestone FGD. This is equivalent to 92.5 percent SO_2 removal in the wet FGD system when firing the worst case design fuel. Using low sulfur coal and dry FGD, Dry Fork will achieve a controlled emission rate almost equivalent to IPP. As shown above, wet FGD is not incrementally cost effective on this project. Therefore, dry FGD is selected as the technology to achieve the BACT SO_2 emission limit for this project of 0.10 lb/mmBtu based on a 3-hour block average.

The EPA NSR RBLC database shows the comparable sources related to sulfuric acid mist (H_2SO_4). They are shown in Table E-9 in Appendix E. Many of the sources determined that the use of a dry lime scrubber followed by a fabric filter was technology chosen to achieve BACT. Most of the other sources selected wet FGD system to achieve BACT emissions levels for sulfuric acid. Sargent & Lundy estimates a 90 percent sulfuric acid control level with the proposed Dry Fork Unit 1 design.

Based on the technology and clearinghouse database discussion above, a dry lime FGD system followed by a fabric filter are selected as BACT for the project with a sulfuric acid emission rate of 0.0025 lb/mmBtu.

5.2.4 NO_x Analysis

The BACT analysis for Nitrogen Oxides is presented below.

Step 1 – Identify All Control Technologies

NO_x will be emitted by combustion of coal in the boiler. NO_x formed in the combustion process consists of fuel NO_x (NO_x derived from nitrogen in the fuel) and thermal NO_x (which is produced from nitrogen in the combustion air) when the peak flame temperature reaches a sufficiently high temperature (approximately 2500°F).

The first step is to evaluate NO_x controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RACT/BACT/LAER Clearinghouse (RBLC) database assessable on the Internet. The printout from the database for NO_x is shown in Appendix E, Table E-8. A broad range of other information sources were also reviewed in an effort to identify all potentially applicable emission control technologies.

Potential NO_x control technology options are:

- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Low NO_x burners with overfire air
- Low NO_x Burners
- Good combustion control

Step 2 – Eliminate Technically Infeasible Options

~~All of these technologies are listed in the RBLC for coal-fired utility boilers, and all of the~~ technologies are technically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for each of the technology combinations are required to rank them in order of effectiveness. These emission rates are provided in Table 5-3. The control efficiencies are those shown in the RBLC database (Appendix E, Table E-8).

The PSD NSR regulations require that BACT, at a minimum, meet the applicable NSPS limit. Because there is an NSPS that applies to the boiler, the NSPS emission limit is also included in the ranking.

TABLE 5-3
NO_x Control Technology Emission Rate Ranking

Control Technology	NO_x Emission Rate [a]
SCR and Low NO_x Burners w/Overfire Air	0.067 – 0.15
SNCR and Low NO_x Burners w/Overfire Air	0.09 - 0.17
Low NO_x Burners with Overfire Air	0.15 – 0.33
Low NO_x Burners	0.32 – 0.39
Combustion Controls	0.23 – 0.55
NSPS Limit	0.16 [b]

[a] Pounds per million BTU as found in the RBLC database.
[b] Converted from NSPS limit of 1.6 pounds per megawatt hour assuming a heat rate of 10,000 BTU per kwh.

Nomenclature:
SCR = Selective catalytic reduction
SNCR = Selective non-catalytic reduction
NSPS = New Source Performance Standards

Step 4 – Evaluate Most Effective Controls and Document Results

SCR is being considered for this project, so its environmental, energy, and economic impacts must be examined. SCR is a control technique that uses ammonia to react with the NO_x in the flue gas at the appropriate temperature in the presence of a catalyst to form water and nitrogen.

SCR has two well-documented environmental impacts associated with it, ammonia emissions (sometimes called ammonia slip) and disposal of spent catalyst. Some ammonia emissions from an SCR system are unavoidable because of imperfect distribution of the reacting gases, and ammonia injection control limitations as well as a partially degraded catalyst that results in an incomplete reaction of the available ammonia with NO_x. Also, the NO_x removal efficiency depends on the ratio of ammonia to NO_x. Increasing the amount of ammonia injected increases the control efficiency but also increases the amount of unreacted ammonia that is emitted to the atmosphere. Ammonia emissions from a well-controlled SCR system can likely be limited to 10 ppmv or less. Ammonia emissions are of concern, because ammonia is a significant contributor to regional secondary particulate formation and visibility degradation. In this case reduced NO_x emissions as an environmental benefit would be traded for increased ammonia emissions as an environmental cost.

The other environmental impact associated with SCR is disposal of the spent catalyst. Some of the catalyst used in SCR systems must be replaced every two to three years. These catalysts contain heavy metals including vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. This must be addressed when handling and disposing of the spent catalyst.

The next control technology in the hierarchy is SNCR. The range of control efficiencies for SNCR ranges above the NSPS so it was not evaluated further. The other technologies listed in Table 5-3 were also not determined to achieve a level of control sufficient to meet NSPS and were not considered further. As such, further evaluation of energy, environmental, and cost data is not required.

Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. EPA's RACT/BACT/LAER Clearinghouse (RBLC), a database of past technology decisions, was again consulted to assist in selecting BACT for this project.

Of the projects found, only SCR with LNBs and Overfire Air is shown to meet NSPS. The installation of low-NO_x burners with Overfire Air, and SCR with a NO_x removal efficiency of 72 percent based on a 0.25 lb/mmBtu NOx inlet will result in an emission rate of 0.07 lb/mmBtu for the Dry Fork Station.

The recent addition of the 750 MW-net MidAmerican Council Bluffs Energy Center (CBEC) Unit 4, which is under construction, was permitted at 0.07 lb/mmBtu based on the use of low-NO_x burners with Overfire Air and SCR. This unit also burns PRB coal. The design NO_x emission rate for Dry Fork is 0.07 lb/mmBtu which is identical to the CBEC Unit 4 design NO_x emission rate, and equal to the lowest emission rate for units in the RBLC. The 950 MW-gross Intermountain Power Project (IPP) Unit 3 was also recently permitted at 0.07 lb/mmBtu based on the use of low-NO_x burners with Overfire Air and SCR. Therefore SCR with Low-NOx Burners and Overfire Air is selected as the technology to achieve the BACT emission limit for this project of 0.07 lb/mmBtu based on a 30-day rolling average.

5.2.5 CO and VOC Analysis

The BACT analysis for CO and VOCs is presented below.

Step 1 – Identify All Control Technologies

Only two control technologies have been identified for control of CO and VOC:

1. Catalytic oxidation
2. Combustion controls

Catalytic oxidation is a post-combustion control device that would be applied to the combustion system exhaust, while combustion controls are part of the combustion system design.

Step 2 – Eliminate Technically Infeasible Options

Catalytic oxidation has been the control alternative used to obtain the most stringent control level for CO and VOCs emitting from primarily combustion turbines firing natural gas. This alternative, however, has never been applied to a coal-fired unit, and thus has not been actually demonstrated in practice in this application.

For sulfur-containing fuels, such as coal, an oxidation catalyst will convert SO_2 to SO_3 and therefore this conversion would result in unacceptable levels of corrosion to the flue gas system. Generally, oxidation catalysts are designed for a maximum particulate loading of 50 milligrams per cubic meter (mg/M^3). The proposed Dry Fork boiler will have a particulate loading upstream of the fabric filter in excess of 5,000 mg/M^3. In addition, trace elements present in coal, in particular chlorine, may deactivate oxidation catalysts making them ineffective. There are no oxidation catalysts developed that have or can be applied to coal- or oil-fired boilers due to the high levels of particulate matter and trace elements present in the flue gas.

Although the catalyst could be installed downstream of the fabric filter to reduce the particulate loading, the flue gas temperature at that point will be approximately 165°F, which is well below the minimum temperature required (600°F) for operation of an oxidation catalyst. The flue gas would have to be reheated, resulting in significant unfavorable energy and economic impacts.

For these reasons, as well as the generally low level of CO and VOC in coal-fired units, no boilers have been equipped with oxidation catalysts. Use of an oxidation catalyst system in the proposed Dry Fork boiler is thus considered technically infeasible. Thus, this alternative cannot be considered to represent BACT for control of CO and VOCs.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the Step 2 analysis, combustion control is the only remaining technology for this application.

Step 4 – Evaluate Most Effective Controls and Document Results

No environmental or energy costs are associated with combustion control in a PC boiler.

Step 5 – Select BACT

The EPA NSR RBLC database for comparable sources related to CO and VOCs is shown in Appendix E, Tables E-1 and E-2. The final step in the top-down BACT analysis process is to select BACT. Based on the above analysis, combustion control in a traditional PC boiler is chosen as the technology to control emissions of CO and VOCs for this project with BACT emission limits of 0.15 lb/mmBtu for CO and 0.0037 lb/mmBtu for VOCs.

5.2.6 PM/PM_{10} Analysis

PM and PM_{10} emissions will be emitted from the main boiler, auxiliary cooling tower, and the coal, ash, sorbent, and lime handling systems. An analysis for the emissions from the boiler is presented, followed by an analysis for the auxiliary cooling tower and then the material-handling systems.

Unit 1 Boiler

Step 1 – Boiler: Identify All Control Technologies

Two control technologies for PC boilers have been identified for PM/PM_{10} control:

1. Electrostatic precipitators (ESPs)
2. Fabric filters

Step 2 – Boiler: Eliminate Technically Infeasible Options

Electrostatic Precipitators

ESP technology is applicable to a variety of coal combustion sources. ESPs remove particulate matter from the flue gas stream by charging flyash particles with a very high DC voltage and attracting these particles to grounded collection plates. A layer of collected particulate matter forms on the collecting plates and is removed by periodically rapping the plates. The collected ash particles drop into hoppers below the precipitator and are removed periodically by the flyash-handling system.

Fabric Filters

Fabric filtration has been applied widely to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use bags of various materials as filters to collect particulate matter. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated particulate matter collected on the fabric of the filter bags. The collected particulate matter forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the dislodged particulate matter is removed by the ash-handling system.

Fabric filters are effective in meeting NSPS emission requirements on coal-fired boilers. Fabric filters have been used as a control technology of choice on projects where LAER review is required. Unlike precipitators, fabric filter design is not based on any physical properties of the flyash.

Step 3 – Boiler: Rank Remaining Control Technologies by Control Effectiveness

The fabric filter is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Large particles have a high mass to surface area ratio, which allows a charged particle to be dragged efficiently through the flue gas stream for collection on a grounded plate. Ultrafine particles have a low terminal velocity and cannot carry a strong enough electrical charge to result in complete collection.

The fabric filter is also more effective at collecting flyash generated from western low-sulfur coals, such as the coal to be combusted at the Dry Fork Station. ESPs operate by first electrostatically charging for collection and then discharging the flyash particles for removal in the ash-handling system. Western low-sulfur coal flyash has a very high electrical resistivity that makes it difficult for the ESP to first charge and then discharge the particles. One solution that has been attempted on western power plants is the use of a hotside precipitator that operates at approximately 800°F as opposed to approximately 250°F operating temperature used on most ESPs. The electrical resistivity of the flyash is lower at this higher temperature. However, even with this change in operating temperature, the ESP is still less effective at collecting flyash in western power plants than is the fabric filter. The use of a fabric filter is also the preferred particulate control device for following a dry lime scrubber.

Step 4 – Boiler: Evaluate Most Effective Controls and Document Results

No negative environmental impacts have been identified for use of a fabric filter to control particulate emissions from coal-fired boilers. There is, however, a high energy demand for this system. Energy is required to overcome the system's (fabric filter and associated ductwork) 8- to 12-inch water gauge pressure drop and miscellaneous loads, such as electric hopper heating. Since baghouse filters are thought to represent the most effective PM/PM_{10} control technique that can be applied to PC boilers, no economic evaluation is warranted.

Step 5 – Boiler: Select BACT

Based on the above analysis and review of the EPA NSR RBLC database (refer to Tables E-3 and E-4 in Appendix E), a fabric filter achieving a filterable PM emission rate of 0.015 lb/mmBtu based on a 3-hour rolling average and a filterable PM_{10} emission rate of 0.012 lb/mmBtu based on a 3-hour rolling average, is selected as BACT for this project.

Unit 1 Auxiliary Wet Cooling Tower

Step 1 – Cooling Tower: Identify All Control Technologies

The only control method for reducing PM/PM_{10} emissions from wet cooling towers is the use of drift eliminators.

Steps 2, 3, and 4 - Cooling Tower - Eliminate Technically Infeasible Options, Rank, and Evaluate

Drift eliminators were the only control technology identified. They are technically feasible and effective. Because there were no other control technologies identified, Steps 3 and 4 were not necessary.

Step 5 – Cooling Tower: Select BACT

Drift eliminators are the only control method identified for control of PM/PM_{10} emissions from cooling towers. Based on the above analysis and the EPA NSR RBLC database available for recent years (refer to Table E-5 in Appendix E), drift eliminators with a control efficiency of 0.0005 percent (gallons of drift per gallon of cooling water flow) are chosen as BACT for the auxiliary wet cooling tower on this project.

Unit 1 Coal, Ash, and Lime Handling Systems

Step 1 – Coal, Ash, and Lime Handling Systems: Identify All Control Technologies

PM and PM_{10} will be emitted from the handling of the coal for the power plant, the ash that results from the combustion process, and lime that is used as a reagent for the dry FGD system. These emissions are fugitive dust that come from the various transfer points in the handling systems for these materials and fugitive dust from the storage and disposal areas. The potential technologies that can be used to control the fugitive dust emissions are as follows for the various operations:

Coal Handling: Potential control technologies for coal storage, transfer, and handling operations include the use of enclosures vented to fabric filters and the use of dry fogging.

Lime Handling: Potential control technologies for lime storage, transfer, and handling operations include the use of enclosures vented to fabric filters.

Ash/FGD Waste Handling: Storage silos and associated transfer operations can be vented to fabric filters for control. Also water sprays with or without wetting agents can be used to control dust.

Coal/Ash/FGD Waste Haul Roads: Potential technologies for control of fugitive emissions on haul roads are the use of paved roads, the use of covered haul trucks, the use of water sprays, the use of dust suppression chemicals, limitation of the speed of haul trucks, or the use of street sweepers on paved roads.

Step 2 – Coal, Ash, and Lime Handling Systems: Eliminate Technically Infeasible Options

All of the potential control technologies listed in Step 1 are technically feasible.

Step 3 – Coal, Ash, and Lime Handling Systems: Rank Remaining Control Technologies by Control Effectiveness

Generally, the use of total enclosure of the material-handling operation vented to fabric filters is the most effective control option. In locations where fabric filters cannot be used, the use of water sprays and dust suppression chemicals are the most effective control methods.

Step 4 – Coal, Ash, and Lime Handling Systems: Evaluate Most Effective Controls and Document Results

Fabric filter dust collectors will be used on all coal, lime and ash storage and handling systems to prevent fugitive particulate emissions. On site coal storage will be in three concrete silos. The fabric filters will have a design outlet grain loading of 0.005 grain per dry standard cubic foot (gr/dscf).

The Dry Fork plant will use water sprays and dust suppression chemicals for dust control on the coal and ash/FGD waste haul roads and the ash disposal landfill.

Step 5 – Coal, Ash, and Lime Handling Systems: Select BACT

Fabric filters will achieve BACT level emissions for the transfer points, silos, and crusher houses on the coal-handling system. Fabric filters will also achieve BACT emission rates for the transfer points and silos on the ash- and lime-handling systems. For material haul roads, water and dust suppression chemicals will be used for dust control.

5.2.7 Fluoride Analysis

Fluoride compounds will be emitted from the boilers from the combustion of coal. The fluoride compounds will be mainly in the gaseous form of hydrogen fluoride (HF) in the flue gas exiting the boiler.

Step 1 – Identify All Control Technologies

Two control technologies for fluoride control of flue gas from the boilers have been identified:

1. Wet Limestone/Lime FGD
2. Dry Lime FGD followed by fabric filter

Step 2 – Eliminate Technically Infeasible Options

Wet Limestone/Lime FGD

Wet SO_2 scrubbers operate by flowing the flue gas upward through a large reactor vessel that has an alkaline reagent (i.e., lime or limestone slurry) flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel. The calcium in the reagent reacts with the fluoride in the flue gas to form calcium fluoride that is removed from the scrubber with the sludge and is disposed.

The creation of sludge from the scrubber does create a solid waste handling and disposal problem. This sludge needs to be handled in a manner to not result in groundwater contamination. Also, the sludge disposal area needs to be set aside permanently from future surface uses because the disposed sludge can not bear any weight from such uses as buildings or cultivated agriculture.

Dry Lime FGD Followed by Fabric Filter

Spray dryers operate by the flue gas flowing upward through a large vessel. In the top of the vessel is a rapidly rotating atomizer wheel through which lime slurry is flowing. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas where the fluorides in the flue gas react with the calcium in the lime slurry to form particulate calcium fluoride. This dry material is captured in the fabric filter along with the flyash and calcium sulfate from the sulfur removal process.

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fiberglass bags as filters to collect particulate matter. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated particulate matter collected on the fabric of the filter bags. The collected particulate matter forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the excess particulate matter is removed by the ash-handling system.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Either control technology will achieve 90 percent or greater control of fluorides.

Step 4 – Evaluate Most Effective Controls and Document Results

Either approach can achieve 90 percent or greater control of fluorides. No negative environmental impacts have been identified for use of a spray dryer absorber followed by a fabric filter to control fluoride emissions from pulverized coal boilers. The use of a wet scrubber has the negative environmental impacts of wet sludge disposal and increased water use for a project in an arid climate.

Step 5 –Select BACT

The EPA NSR RBLC database shows nine comparable sources related to fluoride. They are shown in Table E-7 in Appendix E. Seven of the sources determined that the use of a dry lime scrubber followed by a fabric filter was technology chosen to achieve BACT. The other sources selected an electrostatic precipitator followed by a wet limestone FGD system to achieve BACT emissions levels for fluoride. Sargent & Lundy estimates a 90 percent HF control level with the proposed Dry Fork Unit 1 design.

Based on the technology and clearinghouse database discussion above, a spray dryer FGD system followed by a fabric filter are selected as BACT for the project with a fluoride (as HF) emission rate of 0.00069 lb/mmBtu.

5.2.8 Beryllium Analysis

Beryllium emissions will be emitted from the boiler. Beryllium will accumulate as a component of the fly ash and control technologies that are effective in controlling particulate matter emissions will also control beryllium emissions.

Step 1 – Identify All Control Technologies

Two control technologies for PC boilers have been identified for beryllium control:

1. Electrostatic precipitators (ESPs)
2. Fabric filters

Step 2 – Eliminate Technically Infeasible Options

Electrostatic Precipitators

ESP technology is applicable to a variety of coal combustion sources. ESPs remove particulate matter from the flue gas stream by charging flyash particles with a very high DC voltage and attracting these particles to grounded collection plates. A layer of collected particulate matter forms on the collecting plates and is removed by periodically rapping the plates. The collected ash particles drop into hoppers below the precipitator and are removed periodically by the flyash-handling system.

Fabric Filters

Fabric filtration has been applied widely to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fiberglass bags as filters to collect particulate matter. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated particulate matter collected on the fabric of the filter bags. The collected particulate matter forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the dislodged particulate matter is removed by the ash-handling system.

Fabric filters are effective in meeting NSPS emission requirements on coal-fired boilers. Fabric filters have been used as a control technology of choice on projects where LAER review is required. Unlike precipitators, fabric filter design is not based on any physical properties of the flyash.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The fabric filter is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Large particles have a high mass to surface area ratio, which allows a charged particle to be dragged efficiently through the flue gas stream for collection on a grounded plate. Ultra fine particles have a low terminal velocity and cannot carry a strong enough electrical charge to result in complete collection.

The fabric filter is also more effective at collecting flyash generated from western low-sulfur coals, such as the coal to be combusted at the Dry Fork Station. ESPs operate by first electrostatically charging for collection and then discharging the flyash particles for removal in the ash-handling system. Western low-sulfur coal flyash has a very high electrical resistivity that makes it difficult for the ESP to first charge and then discharge the particles. One solution that has been attempted on western power plants is the use of a hot side precipitator that operates at approximately 800°F as opposed to approximately 250°F operating temperature used on most ESPs. The electrical resistivity of the flyash is lower at this higher temperature. However, even with this change in operating temperature, the ESP is still less effective at collecting flyash in western power plants than is the fabric filter. The use of a fabric filter is also the preferred particulate control device for following a dry lime scrubber.

Step 4 – Evaluate Most Effective Controls and Document Results

No negative environmental impacts have been identified for use of a fabric filter to control particulate emissions from coal-fired boilers. There is, however, a high energy demand for this system. Energy is required to overcome the system's (fabric filter and associated ductwork) 8- to 12-inch water gauge pressure drop and miscellaneous loads, such as electric hopper heating. Since baghouse filters are thought to represent the most effective PM/PM_{10} control technique that can be applied to PC boilers, no economic evaluation is warranted.

Step 5 – Select BACT

The EPA NSR RBLC clearinghouse database shows six comparable sources related to beryllium. They are shown in Table E-10 in Appendix E. Based on the above analysis and the clearinghouse data, a fabric filter preceded by a dry lime FGD system are selected as BACT for the control of beryllium emissions for this project with an estimated emission rate of 0.00097 lb/hr.

5.3 Clean Air Mercury Rule

As a coal-fired power plant, Dry Fork Station will be subject to the Clean Air Mercury Rule (CAMR). The proposed boiler will be designed to comply with CAMR.

5.3.1 Mercury Emissions

Mercury is a naturally occurring constituent of soil and mineral deposits, including deposits of coal. When coal is burned, any trace quantities of mercury present are vaporized at the high temperatures within the furnace section of the boiler. In the presences of chlorine, a portion of the gaseous mercury may react to form mercuric chloride ($HgCl_2$), with most of the remaining mercury emitted as a gas in elemental form. The speciation of the emitted ~~mercury depends on the coal composition (primarily the ash and chlorine content), the~~ combustion system, and the time and temperature history of the flue gas.

The other primary variable affecting mercury emissions is the quantity of mercury contained in the particular coal being burned. Western coals exhibit generally lower mercury content than eastern coals.

5.3.2 CAMR Standards

On March 15, 2005, EPA issued the first ever federal rule to permanently cap and reduce mercury emissions from coal-fired power plants. The Clean Air Mercury Rule establishes "standards of performance" limiting mercury emissions from new and existing coal-fired power plants and creates a market-based cap-and-trade program that will reduce nation-wide utility emissions of mercury. Under the CAMR cap-and-trade program, each state is given a budget of mercury emission allowances. Subsequently, the states allocate the allowances to the affected coal-fired power plants. The number of allowances for each state will remain static from 2010 to 2017, with a large reduction in allowances starting in 2018.

The Dry Fork Station is projected to burn only subbituminous coal and will utilize dry flue gas desulfurization (FGD) technology to limit SO_2 emissions from the steam generating unit. Therefore, the proposed boiler will be subject to the 40 CFR 60.45 Da NSPS mercury limitation of 78 x 10^{-6} lb/MW-hr on an output basis (12 month rolling average).

5.3.3 Mercury Control Technologies

The EPA states that available information indicates that mercury emissions from coal-fired utility units are minimized in some cases through the use of PM controls (fabric filters or ESPs) coupled with an FGD system. For subbituminous coal-fired power generation units in the western U.S. that may face potential water restrictions and, therefore, do not have the option of using a wet FGD system, the best demonstrated technology (BDT) is a combination of either a fabric filter or an ESP coupled with a spray dryer absorber (SDA) [Federal Register Vol. 70, No. 95, May 18, 2005 / Rules and Regulations, page 28614]. Therefore, the Dry Fork Station is being designed with BDT for mercury control.

5.3.4 Dry Fork CAMR Compliance

Assuming an average coal mercury concentration of 0.05 to 0.08 ug/g and the design output rating of the unit, the estimated potential uncontrolled mercury emission rate from the boiler would range from 60.4 to 96.6 x 10^{-6} lb/MW-hr. Therefore, depending on the mercury content of the coal, the unit will need to achieve up to 20 percent mercury control to meet the applicable mercury NSPS. Emission control devices designed to minimize NOx, SO2 and PM10 emissions will provide some mercury control. Depending on how the mercury speciates in the flue gas, the proposed fabric filter and dry lime FGD is projected to have a mercury control level in the range of 10 to 30 percent, which would meet the applicable NSPS requirement under most operating conditions. The proposed unit is being designed with space for a mercury-specific control system (for example, activated carbon injection), and if needed, the mercury control system may provide 50 to 70 percent additional control.

The projected increase in coal-fired power plant construction in Wyoming coupled with the limited state budget for mercury allowances may cause the mercury emission limitation for coal-fired units to become more stringent. In addition, mercury emission limits will be further reduced by CAMR in the year 2018. Therefore, a mercury-specific control system, such as sorbent injection, may be required to achieve compliance with the future emission limits.

5.4 Industrial Boiler MACT for Auxiliary Boiler

This section presents the required MACT analysis for the hazardous air pollutants from the auxiliary boiler subject to the *Industrial Commercial, and Institutional Boilers and Process Heater* NESHAP (40 CFR 60 Subpart DDDDD). The purpose of Subpart DDDDD is to establish national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards. This section does not address MACT for Dry Fork Station Unit 1. Unit 1 is an electric utility steam generating unit that is a fossil fuel fired combustion unit of more than 25 MW that serves a generator that produces electricity for sale, therefore, it is not subject to the Industrial Boiler MACT per 40 CFR 63.7491(c).

The auxiliary boiler is located at, or is part of, a major source of HAP emissions and, therefore, meets the criteria of an "affected" source as described in 40 CFR 63.7490 and is subject to this subpart. The auxiliary boiler is considered a new large gaseous fuel boiler and is subject to the emission limitations, work practice standards, performance testing, monitoring, startup shutdown malfunction plan, and notification requirements described in the rule. The auxiliary boiler will be fired using pipeline quality natural gas only, with no backup fuel, therefore, the only applicable emission limits and work practice standards that Dry Fork must comply with for the auxiliary boiler are for the pollutant CO. CO emissions from the unit are limited to 400 ppm by volume, dry basis, @ 3 percent O_2 on a 30-day rolling average. CO is identified as a surrogate to represent a variety of organic compounds for organic HAP emissions because CO is a good indicator of incomplete combustion and there is a direct correlation between CO emissions and the formation of organic HAP emissions. Also, it is significantly easier and less expensive to measure and monitor CO emissions than to measure and monitor emissions of each individual organic HAP. The formation of CO is limited by controlling the combustion of the fuel and providing adequate oxygen for complete combustion. Thus, good combustion control is the technique to be used to limit CO emissions for the auxiliary boiler.

Compliance with the CO emission limitation is demonstrated by an initial performance test for CO emissions followed by subsequent annual testing. In addition, a CO CEMS must be installed as the unit is larger than 100 MmBtu/Hr heat input. The CEMs must be installed, operated and maintained according to the Performance Specification (PS) 4A of 40 CFR part 60, Appendix B, and according to the site specific monitoring plan described in 40 CFR 63.7505.

Section 6
Permit Limits

SECTION 6.0

Requested Permit Limits

This section presents the permit limits requested in this permit application.

6.1 Potential to Emit for Unit 1

The Potential to Emit (PTE) for Unit 1 were obtained using assumptions on what a newly constructed Unit 1 could achieve through the application of control technology required pursuant to applicable NSPS and BACT for each pollutant under consideration. This includes the following assumptions:

- Fuel and Unit Size
  - A maximum unit size of 422 gross MW and 385 net MW
  - A unit annual capacity factor of 100 percent
  - A maximum design coal sulfur content of 0.47 percent by weight
  - A design coal heating value of 7,800 Btu/lb
- SO_2
  - The use of a dry lime SO_2 flue gas desulfurization system
  - The SO_2 control system will be designed to meet 0.10 lb/mmBtu (3–hour block and 30-day rolling average)
- NO_X
  - The addition of LNBs, overfire air, and SCR control
  - The NO_X control system will be designed to meet 0.07 lb/mmBtu (30-day rolling average)
- Total PM and PM_{10}
  - The use of a fabric filter baghouse
  - The boiler baghouse control system will be designed to meet a filterable PM emission rate of 0.015 lb/mmBtu and a filterable PM_{10} emission limit of 0.012 lb/MMBtu (3-hour rolling average)
- CO
  - The use of good combustion controls to limit CO emissions
- VOC
  - The use of good combustion controls to limit VOC emissions

- Lead
  - The use of a fabric filter baghouse
- Beryllium
  - The use of a fabric filter baghouse
- H_2SO_4 and HF
  - The use of a dry lime SO_2 flue gas desulfurization system

A summary of the emissions for Unit 1 is shown in Section 3.0. These emission rates are the maximum expected emission rates based on continuous operation of the new unit. These maximum hourly emission rates were the basis for Unit 1 modeling analysis.

6.2 PSD Permitting Applicability

The proposed Unit 1 project will be a new major stationary source. The pollutants subject to the Prevention of Significant Deterioration (PSD) program and their significance levels are listed in Section 3.0. The PTE for all criteria pollutants except Lead exceed the applicable annual PSD significant emission rates. Thus, PSD review is applicable to all criteria pollutants except Lead. Section 4.0 provides detailed information on applicable regulations.

The basic PSD permitting requirements that must be met for a major modification include:

- Application of Best Available Control Technology (BACT)
- Performance of an ambient air quality impacts analysis (dispersion modeling)
- Analysis of impacts to soils, vegetation, and visibility
- Analysis of Class I area impacts, including visibility and other air quality related values (AQRVs)

Section 5.0 of this application contains the BACT analysis. Section 8.0 contains the Class I visibility and other impacts analysis and Section 7.0 contains information on the Class II dispersion modeling results.

6.3 Requested Emission Limits

Based on the results of the BACT analysis, Class I visibility modeling and Class II dispersion modeling, BPEC requests the following emission rate limits for the proposed Unit 1 boiler at Dry Fork Station.

SO_2: 0.10 lb/mmBtu heat input based on a 3-hr block average, except during periods of startup, shutdown, maintenance/planned outage, or malfunction. Compliance with the emission limit will be demonstrated using a SO_2 CEMS compliant with the requirements of 40 CFR Part 75.

SO_2: 0.10 lb/mmBtu heat input based on a 30 day rolling average as determined by the ~~arithmetic average of all hourly emission rates for the 30 successive boiler operating days,~~ except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

Compliance with the emission limit will be demonstrated using a SO_2 CEMS compliant with the requirements of 40 CFR Part 75.

SO_2: 1,625 tpy annual 12-month rolling including periods of startup, shutdown and malfunction. Compliance with the emission limit will be demonstrated using a SO_2 CEMS compliant with the requirements of 40 CFR Part 75.

NO_x: 0.07 lb/mmBtu heat input based on a 30 day rolling average as determined by the arithmetic average of all hourly emission rates for the 30 successive boiler operating days, except during periods of startup, shutdown, maintenance/planned outage, or malfunction. Compliance with the emission limit will be demonstrated using a NO_x CEMS compliant with the requirements of 40 CFR Part 75.

NO_x: 1,137 tpy annual 12-month rolling including periods of startup, shutdown and malfunction. Compliance with the emission limit will be demonstrated using a NO_x CEMS compliant with the requirements of 40 CFR Part 75.

PM_{10} (filterable): 0.012 lb/mmBtu heat input except during periods of startup, shutdown, maintenance/planned outage, or malfunction based on the average of three (3) one–hour stack tests conducted annually using USEPA Test Methods 5, 17, 201, or 201A as described in Section 9.0 of this permit application.

PM_{10} (total – including filterable and condensable): 0.017 lb/mmBtu heat input except during periods of startup, shutdown, maintenance/planned outage, or malfunction based on the average of three (3) one–hour stack tests using USEPA Test Methods 201A/202 or modified methods per WDEQ approval, as described in Section 9.0 of this permit application.

Opacity: 20% based on six minute averages except for one 6-minute period per hour that may not exceed 27%.

CO: 0.15 lb/mmBtu heat input based on a 30 day rolling average as determined by the arithmetic average of all hourly emission rates for the 30 successive boiler operating days, except during periods of startup, shutdown, maintenance/planned outage, or malfunction. Compliance with the emission limit will be demonstrated using a CO CEMS compliant with the requirements of 40 CFR Part 60.

CO: 2,437 tpy annual 12-month rolling including periods of startup, shutdown and malfunction. Compliance with the emission limit will be demonstrated using a CO CEMS compliant with the requirements of 40 CFR Part 60.

VOC: 61 tpy on an annualized average based on an emission rate of 0.00385 lb/mmBtu heat input, except during periods of startup, shutdown, maintenance/planned outage, or malfunction. Compliance with the VOC emission rate will be demonstrated based on the average of three (3) on–hour stack tests using USEPA Test Method 25 or 25A as described in Section 9.0 of this permit application.

H_2SO_4: 0.0025 lb/mmBtu. Compliance with the H_2SO_4 emission rate will be demonstrated based on the average of three (3) on–hour stack tests using USEPA Test Method 8 as described in Section 9.0 of this permit application.

HF: 0.00069 lb/mmBtu. Compliance with the HF emission rate will be demonstrated based on the average of three (3) on–hour stack tests using USEPA Test Method 26A as described in Section 9.0 of this permit application.

Mercury: 78 x 10^{-6} lb/MW-hr on an output basis 12 month rolling average. Compliance will be demonstrated with a mercury CEMS per 40 CFR Part 75 requirements.

Section 7

Near-field Modeling

SECTION 7.0

Near-Field Air Quality Impact Analysis

Basin Electric Power Cooperative (BEPC) proposes to construct the Dry Fork Station Project (project) near Gillette, Wyoming. The proposed power plant would include one pulverized coal (PC) boiler that would be capable of generating a nominal 422 MW (gross) of power.

The source of coal for the project will be the Dry Fork Mine. Coal from the mine, which is adjacent to the proposed location for the project, will be delivered to the power plant via a covered, overland conveyor. Emissions associated with the PC boiler will be controlled through various reduction methods. Specifically, the sulfur dioxide (SO_2) emissions will be reduced with dry scrubber equipment. Boiler particulate emissions will be controlled with a fabric filter, and emissions of nitrogen oxides (NO_X) will be controlled by Selective Catalytic Reduction (SCR). The primary cooling of the unit will be done with an air-cooled (dry) condenser.

7.1 Project and Site Description

BEPC proposes to construct the Dry Fork Station approximately four miles northeast of the Gillette-Campbell County Airport. The proposed location is at an approximate elevation of 4,250 feet above mean sea level (msl), in rolling terrain. In general, the terrain trends upward toward the south. Figure 7-1 presents a location map for the project that also depicts the local terrain.

7.2 Regulatory Status

7.2.1 Source Designation

The proposed project will be a major stationary source with respect to the Prevention of Significant Deterioration (PSD) rules established under the Federal New Source Review program. The source will belong to one of the 28 categorical sources listed under PSD regulations with a major source threshold of 100 tons per year of any regulated pollutant (fossil-fuel boilers, combinations thereof, totaling more than 250 million British thermal units per hour heat input). The goals of the air quality modeling analysis were to demonstrate compliance with state and federal air quality regulations that are applicable to the proposed project. CH2M HILL performed a dispersion modeling analysis for each criteria pollutant for which the annual emission rate was equal to or greater than the significant emission rates for PSD analysis (Table 7-1). Table 7-2 summarizes the modeling significance levels, PSD increments, and air quality standards that apply to criteria pollutant emissions from the project.

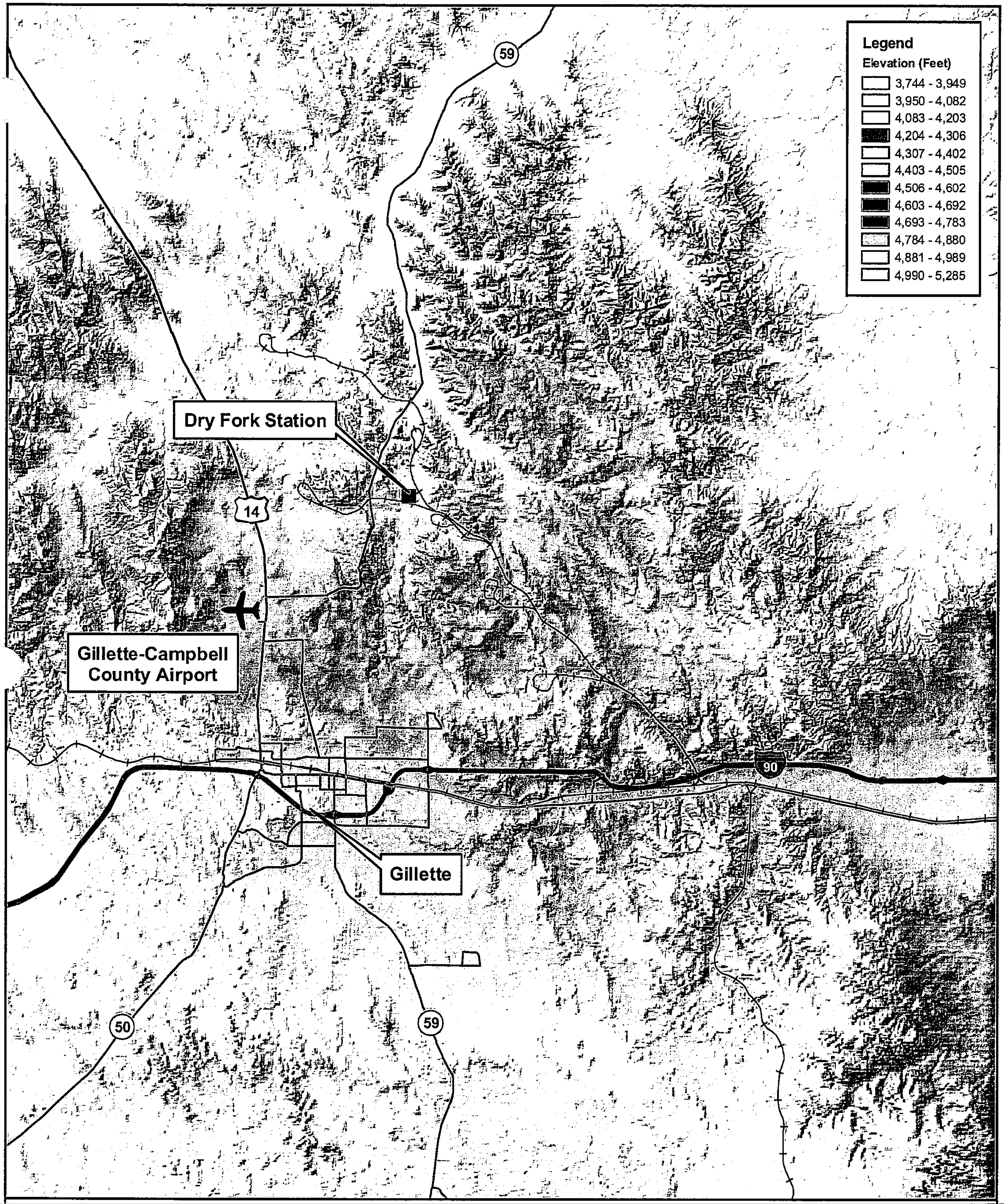


Figure 7-1
Site Location Map for the Dry Fork Station

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TABLE 7-1
PSD Significant Emission Rates

Pollutant	Prevention of Significant Deterioration Significant Emission Rates (tons per year)
Carbon Monoxide (CO)	100
Nitrogen Oxides (NO_x)	40
Sulfur Dioxide (SO_2)	40
Particulate Matter (PM_{10})	15
Ozone	40 (VOC)[1]
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Fluorides	3
Sulfuric Acid Mist	7
Hydrogen Sulfide	10[2]
Total Reduced Sulfur	10[2]
Reduced Sulfur Compounds	10[2]

[1] No "De Minimus" air quality level is provided for ozone. However, any net increase of 100 tons per year or more of volatile organic compounds (VOC) would be required to perform an ambient impact analysis, including the gathering of ambient air quality data.

[2] The emissions of reduced sulfur compounds for the proposed coal-fired boiler are zero. The boiler will be operated with sufficient excess air to ensure complete combustion and oxidation of sulfur in the coal to SO_2 and SO_3.

TABLE 7-2
Air Quality Standards Applicable to the Project

Pollutant (Averaging Period)	Class II Modeling Significance Level (µg/m^3)	Class II PSD Increment (µg/m^3)	National Ambient Air Quality Standard (µg/m^3)	Wyoming Ambient Air Quality Standard (µg/m^3)	PSD Significant Monitoring Concentrations (µg/m^3)
CO (1-hour)	2,000	NS	40,000[a]	40,000[a]	NS
CO (8-hour)	500	NS	10,000[a]	10,000[a]	575
NO_2 (annual)	1	25	100	100	14
SO_2 (3-hour)	25	512	1,300[a]	1,300[a]	NS
SO_2 (24-hour)	5	91	365[a]	260[a]	13
SO_2 (annual)	1	20	80	60	NS
PM_{10} (24-hour)	5	30[a]	150[a]	150[a]	10
PM_{10} (annual)	1	17	50	50	NS
Ozone (1-hour)	NS	NS	0.12	0.12	NS[b]
Ozone (8-hour)	NS	NS	0.08	0.08	NS[b]
Lead (quarterly)	NS	NS	1.5	1.5	0.1

TABLE 7-2
Air Quality Standards Applicable to the Project

Pollutant (Averaging Period)	Class II Modeling Significance Level ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)	National Ambient Air Quality Standard ($\mu g/m^3$)	Wyoming Ambient Air Quality Standard ($\mu g/m^3$)	PSD Significant Monitoring Concentrations ($\mu g/m^3$)
24-hour Beryllium	NS	NS	NS	NS	0.001
24-hour Mercury	NS	NS	NS	NS	0.25
12-hour Fluorides	NS	NS	NS	3.0E+06	NS
24-hour Fluorides	NS	NS	NS	1.8E+06	0.25
7-day Fluorides	NS	NS	NS	0.5E+06	NS
30-day Fluorides	NS	NS	NS	0.4E+06	NS

[a] Not to be exceeded more than once per year.

[b] No monitoring "De Minimus" air quality level is provided for ozone. However, any net increase of 100 tons per year or more of volatile organic compounds (VOC) would be required to perform an ambient impact analysis, including the gathering of ambient air quality data.

Notes:

$\mu g/m^3$ = micrograms per cubic meter
CO = Carbon monoxide
NO_2 = Nitrogen dioxide
NS = No standard
PM_{10} = Particulate matter less than 10 microns
PSD = Prevention of Significant Deterioration
SO_2 = Sulfur dioxide

7.2.2 Area Classifications

The Dry Fork Station Project will be located in Campbell County, Wyoming in an area that is designated as attainment for all criteria pollutants. Areas surrounding the station are designated as Class II areas for PSD permitting. The nearest non-attainment area is located near the town of Sheridan, Wyoming. This area was once designated as non-attainment for particulate matter (PM_{10}) but has since applied for redesignation for attainment status. This area is well beyond the impact area of the proposed project.

7.2.3 Baseline Dates

7.2.3.1 Major Source Baseline Date

The major source baseline date is the date after which actual emissions associated with construction at a major stationary source affect the available PSD increment. The major source baseline dates are established dates that have elapsed. These dates are as follows:

PM_{10} – January 6, 1975
SO_2 – January 6, 1975
Nitrogen dioxide (NO_2) – February 8, 1988

7.2.3.2 Minor Source Baseline Date

The minor source baseline date identifies the point in time after which actual emissions changes from all sources (major and minor) affect available increment. The amount of PSD increment consumption within an area is determined from the actual emission increases and decreases that have occurred since the applicable baseline date. The minor source baseline dates for the state of Wyoming for SO_2 and NO_2 are as follows:

SO_2 – February 2, 1978
NO_2 – February 26, 1988

For PM_{10}, there are three baseline areas that have been designated as separate particulate matter attainment areas under Section 107 of the Clean Air Act (WDEQ, 2003a). The proposed project would be located within one of those areas, the Powder River Basin Area. For this area, the minor source baseline date was triggered in 1997. For all other areas in the state, the PM_{10} minor source baseline date is February 22, 1979.

7.3 Modeling Analysis Design

7.3.1 Model Selection

Air quality impacts from the Dry Fork Station were determined with the latest version of the EPA Industrial Source Complex Short-Term (ISCST3) model that incorporates enhanced building downwash algorithms. The enhanced downwash algorithms are referred to as Plume RIse Model Enhancements (PRIME), and the model as ISC-PRIME (version 04269).

7.3.2 Model Input Defaults/Options

The ISC-PRIME model was used with regulatory default options as recommended in the EPA Guideline on Air Quality Models (EPA, 2003) as listed below:

- Use stack tip downwash (except for Schulman Scire downwash)
- Use buoyancy induced dispersion (except for Schulman Scire downwash)
- Do not use gradual plume rise (except for building downwash)
- Use the calms processing routines
- Use upper bound concentration estimates for sources influenced by building downwash from super squat buildings
- Use default wind profile exponents
- Use default vertical potential temperature gradients

CH2M HILL used the non-default model option for processing missing meteorological data. By using the missing data processing routine, the model can recognize the periods of missing data and adjust calculated impacts. This option is similar within ISC-PRIME to the calms processing option.

The land surrounding Dry Fork in all directions is open country with no significant development. Therefore, rural dispersion coefficients were utilized within the ISC-PRIME model.

Point sources were modeled with stack heights that did not exceed good engineering practice (GEP) stack height. Building downwash parameters for the point sources at Dry Fork Station were determined with the latest version of the EPA Building Profile Input Program (BPIP) designed for the ISC-PRIME model (BPIP-Prime). GEP for all of the point sources, as determined with BPIP-Prime, was 167.64 m (550 feet). The GEP height was driven by the boiler building and the proximity of all point sources to that structure.

7.4 Receptor Network

7.4. 1 Receptor Configuration

The base receptor grid for ISC-PRIME consisted of rectangular, Cartesian arrays of receptors with spacing that increased with distance from the origin. The base grid originated at the proposed location of the Dry Fork Station boiler stack. Receptor spacing, in accordance with WDEQ guidance (WDEQ, 2003b), was as follows:

- 50-meter (m) spacing for ambient boundary (fenceline) receptors
- 100-m spacing from the ambient boundary to 1 km from the origin
- 500-m spacing from beyond 1 km to 5 km from the origin
- 1,000-m spacing from beyond 5 km to 50 km from the origin

CH2M HILL supplemented the base receptor grid with receptors at closer (tighter) receptor spacing, where appropriate, to ensure that the maximum points of impact were identified.

7.4.2 Receptor Elevations

Terrain in the vicinity of the Dry Fork Station was accounted for by assigning elevations to each modeling receptor. CH2M HILL used Digital Elevation Model (DEM) data from the U.S. Geological Survey (USGS) to determine receptor elevations. We obtained DEM data from the USGS National Elevation Dataset (NED). For any areas for which 10-m resolution data was not available, CH2M HILL used DEM files with 30-m resolution.

Universal Transverse Mercator (UTM) coordinates for the modeled sources, downwash structures, and receptors were based on the North American Datum of 1983 (NAD 83), and UTM Zone 13.

7.5 Meteorology

7.5.1 Meteorological Data for Class II Area Modeling

CH2M HILL used surface meteorological data collected at a 100-m meteorological tower as input to the ISC-PRIME model. The 100-m tower, located southeast of Gillette, was operated by BEPC from October 2001 through July 2003. The 100-m tower was equipped with meteorological sensors at 2 m, 10 m, 50 m, and 100 m.

CH2M HILL processed the data using the EPA Meteorological Processor for Regulatory Models (MPRM, version 99349). For the air impact analysis for this project, data for the full calendar year from January 1, 2002 through December 31, 2002 were processed into model-ready format. Model-ready files with hourly wind speeds and directions from the 10-m level and 100-m level of the tower were produced. Hourly atmospheric stability was determined with multiple methods. These methods included:

- ~~Standard deviation fluctuations in horizontal wind direction (sigma theta) at 10 m~~
- Solar radiation/delta-T (SRDT) for the temperature difference from 2 m to 10 m
- SRDT for the temperature difference from 2 m to 50 m

These multiple techniques were used to determine the hourly Pasquill-Gifford (P-G) atmospheric stability so that the resulting stability distributions could be compared, and the best distribution could be chosen for modeling. For each technique, MPRM used a backup method to determine the stability for any hour that was missing the data needed for the primary technique. For the primary SRDT methods, 10-m sigma theta was used as the backup method. For the primary sigma theta method, the 2-10 m SRDT was used as a backup.

The SRDT method uses the surface layer wind speed (measured at 10 m) in combination with measurements of total solar radiation during the day and low-level vertical temperature difference at night. According to EPA guidance, the temperature difference for use in estimating the P-G stability categories using the SRDT method should be measured between $20z_0$ and $100z_0$, with z_0 representing the surface roughness of the measurement site (EPA, 2000). As shown in Table 3-6 of the MPRM User's Guide (EPA, 1996), the seasonal roughness lengths for terrain types most like the measurement site would range from 0.001 m to 0.10 m for "grassland", and between 0.15 m and 0.30 m for "desert shrubland". Therefore, the most appropriate delta-T measurements available from the tower would be 2-10 m and 2-50 m (rather than 2-100 m), and both of these were used for comparison. After examination of the stability distributions within the model-ready files produced with SRDT and those with sigma theta, the files produced with sigma-theta were chosen for use in the project modeling.

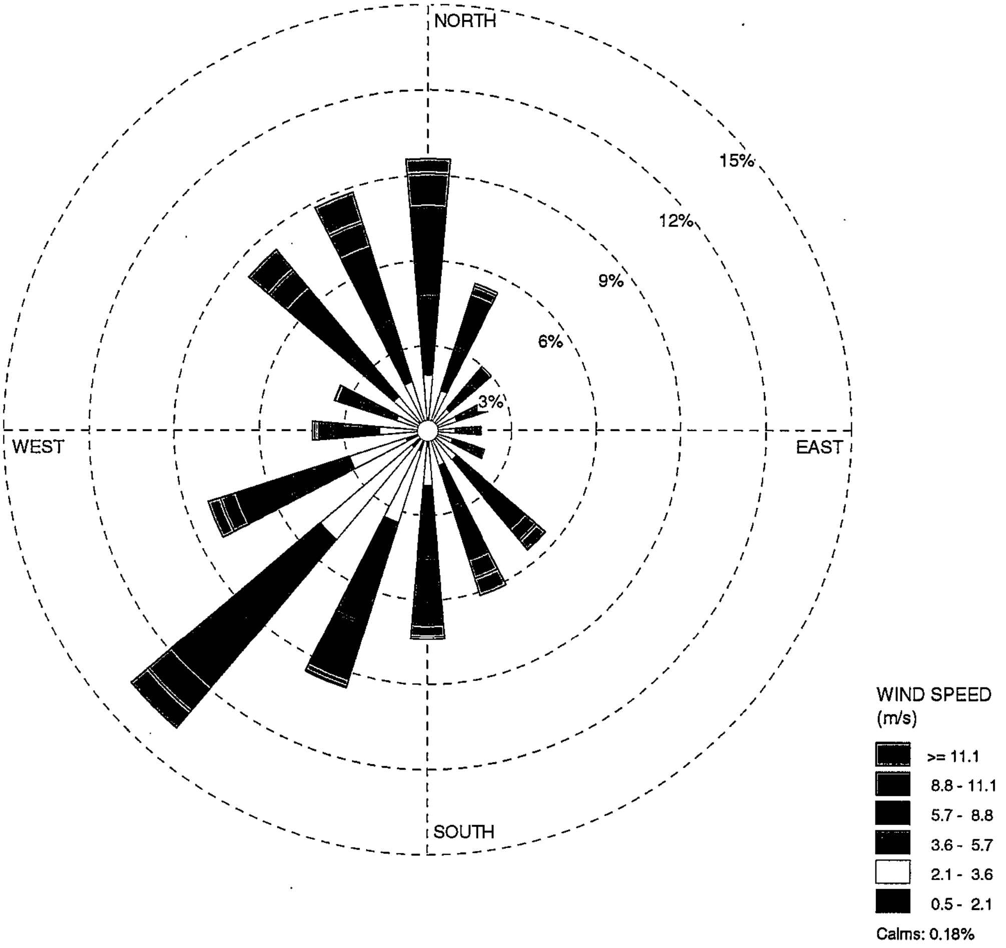
The raw data from Basin's 100-m tower includes a 2-week period in August of 2002 for which all data are missing due to an elevator failure on the tower. CH2M HILL used data collected at the nearby Gillette-Campbell County Airport to fill this data gap. Data from the Gillette airport was processed with the EPA PCRAMMET model to obtain data in model-ready format. For substitution of the Gillette data into the 100-m model-ready file, the 10-m wind speeds from the airport were adjusted to the 100-m level using the power law equation (equation 1-6) in Volume II of the ISC3 User's Guide (EPA, 1995b). CH2M HILL developed site-specific wind profile exponents by solving for the exponent in the power law equation with wind data from the 10-m and 100-m levels from the Basin 100-m tower. The MPRM processing and the use of Gillette-Campbell County Airport to fill this data gap, as discussed above, was determined to be appropriate by WDEQ and approved for use for all ISC-PRIME modeling.

For model runs that included emissions from the proposed boiler stack only, CH2M HILL used the model-ready file that contained winds measured at the 100-m level to allow for the best possible approximation of the winds at the boiler stack height (500 feet). This meteorological input file was also used for the model run for annual NO_x impacts that included the boiler and auxiliary boiler.

For modeling PM_{10} impacts, the project emissions inventory included sources released from near the surface (haul roads and landfill activity) and other point sources with lower release heights than the boiler stack. Because the maximum impacts from PM_{10} were expected to occur near the facility boundary, where the contribution from the boiler stack would be small, CH2M HILL used the model-ready file containing winds measured at the 10-m level for PM_{10} modeling. This allowed for a better approximation of the dispersion from the full suite of PM_{10} sources. Wind roses for the 10-m and 100-m files are presented as Figures 7-2 and 7-3, respectively.

WIND ROSE PLOT:
Station #0 - Basin 100-m Tower: 10-m Winds Gillette, WY

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:
2002
Jan 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:
0.18%

TOTAL COUNT:
8696 hrs.

AVG. WIND SPEED:
5.53 m/s

DATE:
10/28/2005

PROJECT NO.:

WRPLOT View - Lakes Environmental Software

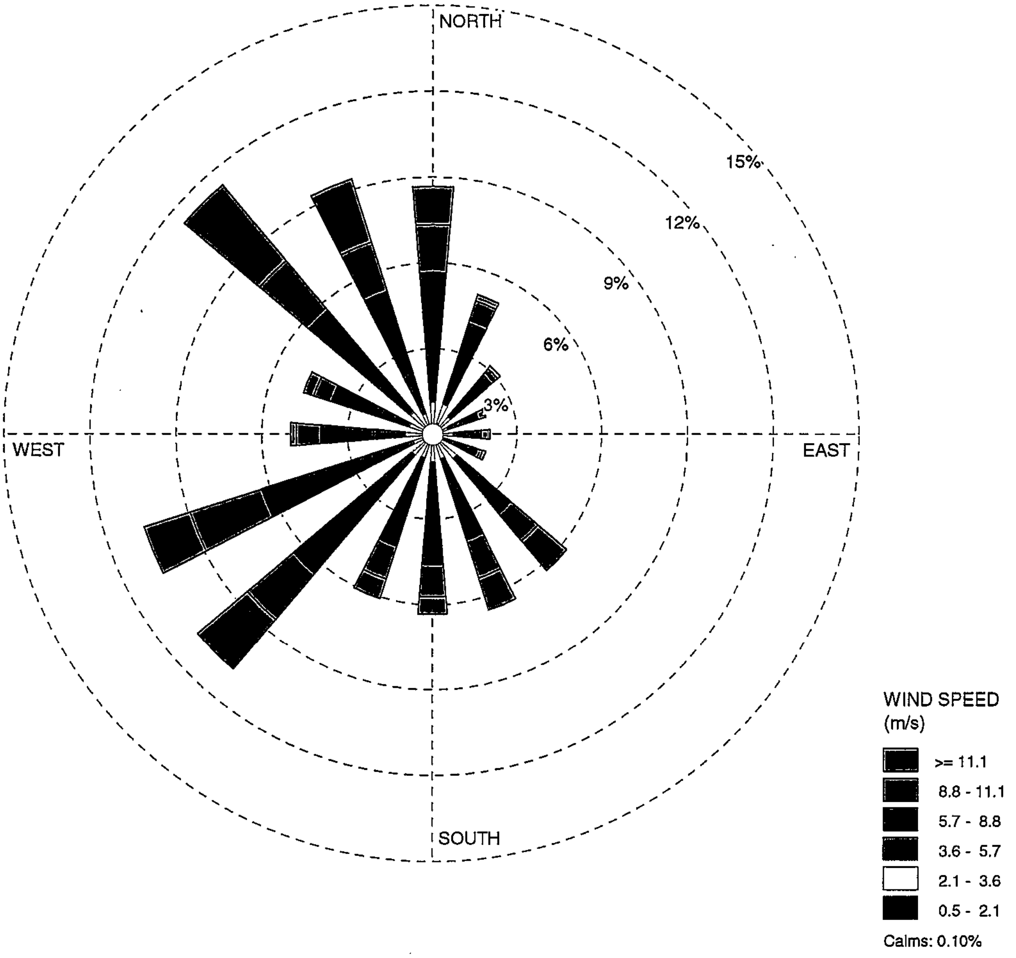
FIGURE 7-2
Wind Rose for 10-meter Meteorological Input File

WIND ROSE PLOT:

Station #0 - Basin 100-m Tower: 100-m Winds Gillette, WY

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:

2002
Jan 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

0.10%

TOTAL COUNT:

8666 hrs.

AVG. WIND SPEED:

7.64 m/s

DATE:

10/28/2005

PROJECT NO.:

WRPLOT View - Lakes Environmental Software

FIGURE 7-3
Wind Rose for 100-meter Meteorological Input File

7.5.2 Upper Air Data for Class II Area Modeling

Hourly mixing heights for all of the MPRM scenarios were derived from twice-daily upper air soundings from Rapid City, South Dakota. Twice-daily mixing heights for Rapid City, which is the nearest upper-air station to the modeling domain, were obtained from the National Climatic Data Center (NCDC). If a single AM or PM mixing height was missing, a linear interpolation of the valid data from the previous day and the following day was used to substitute for the missing value. If more than one AM or PM value was missing, the seasonal average value from the EPA Holzworth reference (EPA, 1972) was used as a substitute. The twice-daily mixing heights from Rapid City were combined with the surface data from the 100-m tower and transformed into model-ready format using MPRM.

7.6 Emission Source Characterization

CH2M HILL modeled the various emission sources at Dry Fork Station as point, area, and volume sources, depending on the nature of the particular source. Sources that emit from a stack, including PM_{10} sources from the auxiliary cooling towers cells and material handling dust collectors, were modeled as point sources. Fugitive emissions from the landfill were modeled as an area source within ISC-PRIME. Area source length and width approximated the actual dimensions of an area that could experience landfill dumping and maintenance in a given day. Although the landfill dumping and maintenance will occur well below grade within the landfill (up to 100 feet in depth), the landfill area source was conservatively modeled as a surface-based source. The area source release height was set to 15 feet to represent a typical average height at which dumping and maintenance activities would occur. No initial vertical dimension was input for the landfill area source, which is an additional conservative assumption.

Fugitive particulate emissions from haul roads were modeled as a series of volume sources. Volume source parameters for the haul roads were taken in part from the EPA document *Modeling Fugitive Dust Impacts from Surface Coal Mining Operations – Phase II Model Evaluation Protocol* (EPA, 1994). The source height of the haul road volume sources was set to 2 m, as based on the statement from the EPA document that the maximum mass flux from haul road dust plumes occurs at that height. Initial vertical dispersion terms (3 m) for the haul road volumes were also taken from the EPA document. The initial horizontal dispersion terms were calculated from the separation distance of the volume sources (approximately two road widths, or 100 feet) in accordance with recommendations in the *User's Guide For The Industrial Source Complex (ISC3) Dispersion Models, Volume I – User Instructions* (EPA, 1995). Initial horizontal dimensions for the volume sources were determined from Table 3-1 in the ISC3 User's Guide using the factor for a "line source represented by separated volume sources."

Material transfer emission points that are not controlled by dust collectors or other control equipment were also modeled as volume sources. These volume sources were elevated at an appropriate height representative of the actual release height of the source, and with initial dimensions that approximate the actual lateral and vertical extent of the source. For this project, the only source in this category was the truck loading at the fly ash/FGD waste silo.

The point, area, and volume sources were placed where actual operations occur. Figure 7-4 (map pocket) shows the detailed layout of the facility and the location of the various modeled sources. Figure 7-5 (map pocket) shows the complete ambient air quality boundary (fenceline) for the project, included the landfill area. Detailed emissions calculations for each project source are presented in Appendix B. Listings of other source input parameters for point sources and volume sources (source heights, stack diameters, exhaust temperatures, etc.) are presented in Appendix G.

7.7 Preliminary Analysis Overview

For a preliminary analysis of the impacts from the Dry Fork Station, CH2M HILL compared the maximum model-predicted impacts from the sources associated with the project to the modeling significance levels (SIL) for Class II areas. If the predicted impacts were greater than or equal to the SIL for any pollutant, CH2M HILL conducted a full-impact analysis for compliance with the Wyoming Ambient Air Quality Standards (WAAQS) and the National Ambient Air Quality Standards (NAAQS) and PSD increments listed in Table 7-2.The determination of preliminary impacts for the proposed project was made using the highest modeled impact for each pollutant and averaging period.

7.7.1 Load Screening Analysis

CH2M HILL began the preliminary analysis by performing a screening analysis of the boiler stack at various operating conditions. Operation at peak load (103 percent load), full load (100 percent load) and at selected reduced loads (75 percent and 50 percent) was evaluated to determine which operating condition produces the highest predicted impacts. The load condition that yielded the highest impacts for a particular averaging period was used to represent the boiler in subsequent modeling analyses. The 100-m meteorological dataset was used for the load screening. Table 7-3 presents the exhaust characteristics for the boiler screening analysis.

TABLE 7-3
Input Parameters for Boiler Stack Load Screening

Parameter	103 percent Load	100 percent Load	75 percent Load	50 percent Load
Exit Velocity (meters/second)	25.65	24.24	18.97	13.22
Exhaust Temperature (°Kelvin)	350	350	350	350

The load screening model run was conducted with source groups for each load level and an emission rate of 1 gram per second (g/s). This allowed for scaling the raw model results by the actual emission rates for each pollutant. Table 7-4 presents the raw results of the analysis at 1 g/s. Operation at full (100 percent) load would yield impacts for the annual averaging period, and therefore, full load was used to represent the boiler for annual averaging period. Operations at both peak (103 percent) load and full (100 percent) load would yield impacts for the short term averaging periods, with operations at full load more typical than at peak load. A detailed breakdown of the scaling of the raw results with actual emission rates for each pollutant is presented in Appendix G. The maximum scaled results, compared to modeling significance levels and monitoring de minimus levels is presented in Section 7.7.2.

TABLE 7-4
Raw Results of Boiler Stack Load Screening (at 1 gram per second)

Parameter	Maximum Predicted Impact for 103 percent Load (μg/m^3)	Maximum Predicted Impact for 100 percent Load (μg/m^3)	Maximum Predicted Impact for 75 percent Load (μg/m^3)	Maximum Predicted Impact for 50 percent Load (μg/m^3)
1-Hour	1.19	1.19	1.21	1.51
3-Hours	0.44	0.45	0.50	0.61
8-Hours	0.21	0.21	0.24	0.29
24-Hour	0.16	0.12	0.16	0.21
Annual	n/a	0.0086	n/a	n/a

7.7.2 Preliminary Analysis for Boiler Stack Emissions (Non-PM_{10} Pollutants)

The next step in the analysis was to evaluate the impacts of pollutants that would be emitted only from the boiler stack (non-PM_{10} pollutants). The pollutants and the maximum modeled impacts (independent of boiler load) are presented in Table 7 5. The maximum impacts were determined with the base ISC-PRIME receptor grid supplemented, where needed, with receptors with 100-m spacing. The one exception was CO, which yielded impacts less than 5 percent of the SIL with the base grid. All predicted impacts were well below Class II area SIL and monitoring de minimus levels, with the exception of 24-hour SO_2, for which the predicted impacts exceeded the SIL.

TABLE 7-5
Preliminary Analysis: Maximum Impacts of Non-PM_{10} Pollutants from the Boiler Stack

Pollutant	Averaging Period	Maximum Predicted Project Impacts (μg/m^3)	Class II Modeling Significance Level (μg/m^3)	Monitoring De Minimus Level (μg/m^3)
CO	1-Hour	85.2	2000	n/a
CO	8-Hour	14.9	500	575
NO_2	Annual	0.3	1	14
SO_2	3-Hour	21.1	25	n/a
SO_2	24-Hour	5.8	5	13
SO_2	Annual	0.4	1	n/a
Lead	3 Months*	0.00009	n/a	0.1
Mercury	24-Hour	0.0002	n/a	0.25
Beryllium	24-Hour	0.00004	0.0002	0.001
Fluorides	12-Hour	0.15	3.0E+06**	n/a
Fluorides	24-Hour	0.04	1.8E+06**	0.25
Fluorides	7 days	0.04	0.5E+06**	n/a
Fluorides	30 days	0.04	0.4E+06**	n/a

* Impacts for 3-month/quarterly lead and 7-day fluoride were conservatively modeled with the 24-hour results within ISC-PRIME.

** No modeling significance level is established for fluorides, but the Wyoming Ambient Air Quality Standards are shown for comparison to the modeled impacts for the project.

7.7.3 Preliminary Analysis for Nitrogen Oxides (NO_X)

For the preliminary analysis of the impacts of NO_X emissions for the project, the main boiler and the natural-gas fired auxiliary boiler were modeled together, with NO_X emission rates that reflect the potential annual operating conditions for each source. The main boiler was modeled with exhaust parameters and emissions reflective of the load condition (100 percent) that would persist for most of an annual period of operation. For the auxiliary boiler, an annual average emission rate for NO_X was calculated from the potential annual hours of operation (2,000) for the source.

The highest predicted annual impact of NO_X with the base ISC-PRIME receptor grid was well below the Class II modeling significance level of 1.0 $\mu g/m^3$ for annual NO_X. To further refine this estimated impact, a fine-spaced receptor grid with 100-meter spacing was built around the maximum coarse-grid receptor. With this fine-spaced grid, the maximum estimated annual impact was 0.29 $\mu g/m^3$. The preliminary analysis demonstrated that the Dry Fork Station Project will not produce a significant impact of annual NO_X.

7.7.4 Radius of Impact for Sulfur Dioxide (SO_2)

With predicted 24-hour impacts for the main boiler exceeding the Class II modeling significance levels, the impact area for SO_2 was determined. The impact area for a particular pollutant, as described in the draft EPA *New Source Review Workshop Manual* (EPA 1990), is "a circular area extending from the source to the most distant point where approved dispersion modeling predicts a significant impact will occur". The impact area will define the area over which the analyses for WAAQS and NAAQS compliance and PSD increment consumption will be performed. For SO_2, the impact area was determined at each load for the 24-hour averaging period, and the area used for further modeling was the largest of the impact areas. For the project, the largest impact area had a radius of 9.1 kilometers. Table 7-6 presents the results of the radius of impact analysis for SO_2 for the 24-hour averaging period. Figure 7-6 shows the extent of the receptor grid that was used for the full-impact analysis for SO_2. The receptor grid for the full-impact analysis including the fine-spaced receptors that were added to the base grid to refine the results for the preliminary analysis.

TABLE 7-6
Results of Radius of Impact Analysis for SO_2

Boiler Load	Maximum Predicted Impact for Boiler ($\mu g/m^3$)	Radius of Impact (km)
103%	5.53	9.1
100%	5.75	9.1
75%	5.79	7.9
50%	5.38	5.6

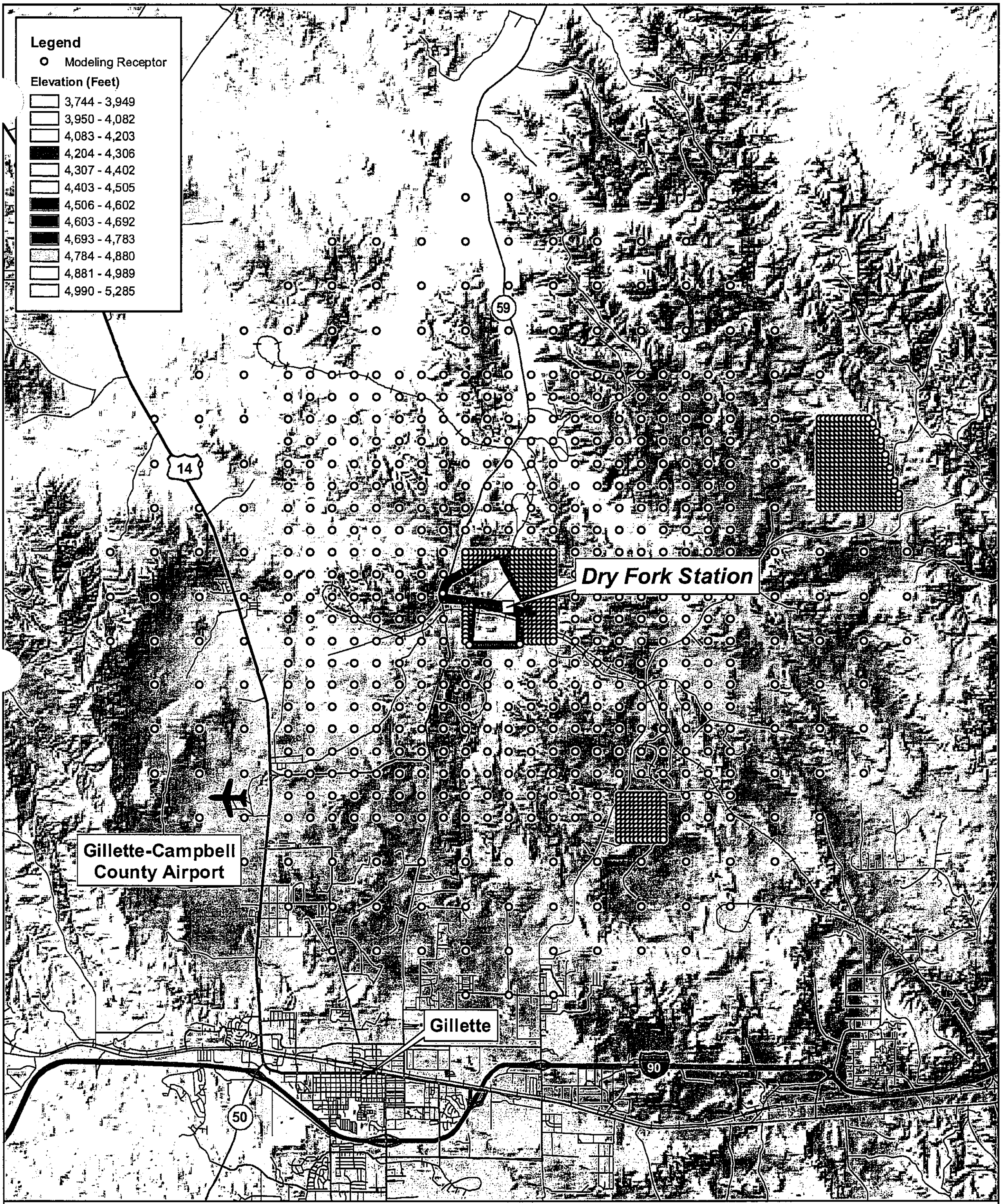


Figure 7-6
Receptor Grid for Radius of Impact for Sulfur Dioxide

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7.7.5 Preliminary Analysis for PM_{10}

The preliminary analysis for PM_{10} included the proposed boiler, the auxiliary cooling tower, and sources associated with material handling for the new unit. Dust collectors and bin vent filters will serve as emissions controls for many of the material handling sources. The sources associated with fly ash/FGD waste/bottom ash handling, including the loading of haul trucks, hauling, and the dumping of material into the landfill, were modeled with a 12-hour per day operation (0600-1800 daily). Detailed emissions calculations for all sources are provided in Appendix B.

The highest predicted 24-hour impact of PM_{10} with the base ISC-PRIME receptor grid and 10-m meteorological data was 4.2 µg/m^3, which is well below the Class II modeling significance level of 5.0 µg/m^3 for 24-hour PM_{10}. This predicted impact occurred approximately 1 km to the northeast of the boiler stack, at the edge of the portion of the base receptor grid with 100-m spacing. To further refine this estimated impact, a fine-spaced receptor grid with 100-meter spacing was built around the maximum course-grid receptor. With this fine-spaced grid, the maximum estimated 24-hour impact remained at 4.2 µg/m^3.

The highest predicted annual impact of PM_{10} with the base ISC-PRIME receptor grid and 10-m meteorological data was 0.89 µg/m^3. This impact was predicted to occur at the facility fenceline to the northeast of the power block. Because this receptor was located in an area of 50-m spacing, no further analysis was required to further refine the impact, which is below the Class II modeling significance level of 1.0 µg/m^3 for annual PM_{10}.

The preliminary analysis demonstrates that the Dry Fork Station Project will not produce a significant impact of PM_{10}. Table 7-7 presents the results of the preliminary analysis for PM_{10}.

TABLE 7-7
Results of Preliminary Analysis for PM_{10}

Averaging Period	Maximum Project Predicted (µg/m^3)	Class II Modeling Significance Level (µg/m^3)
24-Hour PM_{10}	4.20	5
Annual PM_{10}	0.89	1

7.7.6 Full-Impact Analysis for Sulfur Dioxide (SO_2)

Results of the preliminary modeling analysis for SO_2 indicated that predicted impacts from the Dry Fork Station Project would exceed the 24-hour modeling significance level, and therefore the project would trigger a full-impact analysis for 24-hour SO_2. A full-impact analysis includes model runs for the determination of compliance with WAAQS/NAAQS and PSD increments.

To determine compliance with the allowable PSD increment for 24-hour SO_2, CH2M HILL modeled the Dry Fork Station boiler and other increment-consuming sources and compared the highest predicted 2nd-high 24-hour impact to the allowable Class II 24-hour increment of 91 µg/m^3.

To determine compliance with the allowable WAAQS/NAAQS for 24-hour SO_2, CH2M HILL modeled the Dry Fork Station boiler and all appropriate outside sources of SO_2 and added an appropriate background level to arrive at total predicted impacts. The highest predicted 2nd-high 24-hour total impact was compared to the 24-hour WAAQS of 260 µg/m^3 and the 24-hour NAAQS of 365 µg/m^3.

For background concentrations, CH2M HILL used ambient SO_2 data that have been collected at the WYODAK facility in Gillette. These measured concentrations represent conservative representations of background levels for the Gillette area given the presence of several large sources of SO_2 at the WYODAK complex. For 24-hour background, CH2M HILL used the highest 2nd-high value measured at the site from 2003 through mid-2005 (51.8 µg/m^3).

Input data for outside sources in Wyoming were provided by the WDEQ or assembled at WDEQ's offices. The master list of significant sources of SO_2 within the radius of impact plus 50 km included the following sources:

- Wygen1
- Wygen2
- Neil Simpson Unit 1
- Neil Simpson Unit 2
- Wyodak Unit 1
- KFX

All of these source were included in the WAAQS/NAAQS analysis. For PSD increment modeling, all of the listed sources were included with the exception of Wyodak Unit 1. This source was constructed in 1972, which is prior to the major source baseline date for SO_2. In December of 1986, a scrubber was installed to control SO_2 emissions. With the installation of the scrubber, current short-term SO_2 emissions would be lower than the emissions during the baseline period. Therefore, the source would actually expand increment, but rather than account for increment expansion from this source, it was merely removed from the increment analysis. All other Wyoming sources were modeled with their respective allowable short-term SO_2 emissions for the WAAQS/NAAQS analysis, and conservatively modeled with the same allowable emission rates for the PSD increment analyses. Detailed input parameters for each source are provided in Appendix G.

The base ISC-PRIME receptor grid was reduced to include only the receptors that fall within the radius of impact (9.1 km), and this reduced grid was used for the WAAQS/NAAQS and increment analyses (see Figure 7-6). The Dry Fork Station boiler was conservatively modeled with the exhaust parameters for the load (75%) that yielded the highest impacts in the preliminary analysis, along with the emission rate representative of peak (103%) load.

For the WAAQS/NAAQS analysis, the highest 2nd-high 24-hour modeled impact was 55.4 µg/m^3. This modeled impact occurred approximately 9 km southeast of the Dry Fork Station at the edge of the receptor grid. Because this maximum receptor is located in an area of 1-km receptor spacing, a fine-spaced receptor grid was constructed around the maximum receptor to further refine the result. Using the fine-spaced (100-m) receptor grid, the 2nd-high 24-hour modeled impact was 59.1 µg/m^3. The total predicted impact, consisting of the 24-hour ~~background level of 51.8 µg/m^3 added to the modeled impact, was 110.9 µg/m^3. This total~~

impact is well below the 24-hour WAAQS of 260 µg/m³ and the 24-hour NAAQS of 365 µg/m³.

For the PSD increment analysis, the highest 2nd-high 24-hour modeled impact was 40.9 g/m³. This modeled impact also occurred approximately 9 km southeast of the Dry Fork Station at the same receptor that yielded the maximum coarse-grid WAAQS/NAAQS result. Using a fine-spaced (100-m) receptor grid to further refine the result, the 2nd-high 24-hour modeled impact was 52.5 µg/m³, which is well below the 24-hour PSD increment of 91 µg/m³.

Figure 7-7 shows the location of the modeled maximum concentrations and the locations of all modeled sources. Table 7-8 presents the results of the full-impact analysis for SO_2.

TABLE 7-8
Summary of Full-Impact SO_2 Modeling

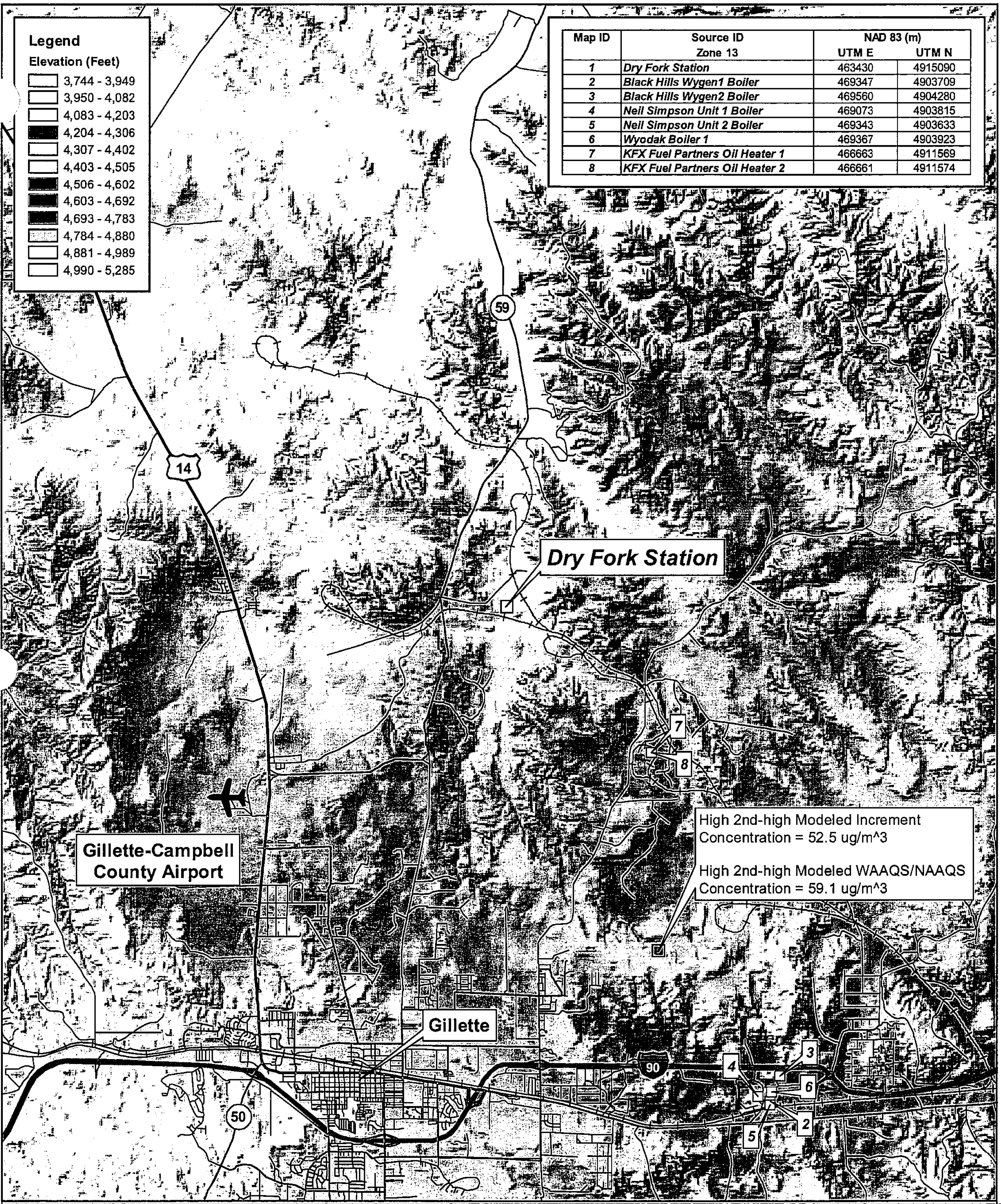
Averaging Period/ Pollutant	High 2nd-High Modeled Increment Impact (µg/m³)	Class II PSD Increment (µg/m³)	High 2nd-High Modeled WAAQS/ NAAQS Impact (µg/m³)	Background Concentration (µg/m³)	Total WAAQS/ NAAQS Impact (µg/m³)	Wyoming (National) Ambient Air Quality Standard (µg/m³)
24-hour SO_2	52.5	91	59.1	51.8	110.9	260 (365)

7.8 Additional Impact Analysis

7.8.1 Growth Analysis

CH2M HILL consulted with BEPC personnel to obtain information on labor requirements and labor availability for the project, and made the following determinations. Most of the approximately 623 construction jobs (peak) needed for the project will be filled by workers commuting to the site, many from the greater Gillette area and Campbell County. Of the permanent positions needed for the project (up to 75), it is assumed that the majority will be filled by local workers, with the remainder filled by people who will relocate to the area. Based on the *State of Wyoming, Department of Administration and Information, Economic Analysis Division, 2004* report, the population of Campbell County in 2000 was 33,698. Even if all 75 positions were filled through relocations, this represents less than 0.2 percent of the population of Campbell County (based on population in 2000). Due to the need for temporary and permanent positions for the project, there will be some emissions associated with the construction of housing in the Gillette area. However, these emissions will be temporary and, because of the limited numbers of new homes expected, are considered to be insignificant.

Services and maintenance mechanisms are already in place in the Gillette area to serve existing power generating facilities. Existing firms located in Gillette and Campbell County provide such services. The need for such services due to the addition of Dry Fork Station is expected to present an increased level of activity for such firms, but is not expected to result in any significant new commercial growth in the Gillette area.



Map ID	Source ID Zone 13	NAD 83 (m) UTM E	 UTM N
1	*Dry Fork Station*	463430	4915090
2	*Black Hills Wygen1 Boiler*	469347	4903709
3	*Black Hills Wygen2 Boiler*	469560	4904280
4	*Neil Simpson Unit 1 Boiler*	469073	4903815
5	*Neil Simpson Unit 2 Boiler*	469343	4903633
6	*Wyodak Boiler 1*	469367	4903923
7	*KFX Fuel Partners Oil Heater 1*	466663	4911569
8	*KFX Fuel Partners Oil Heater 2*	466661	4911574

High 2nd-high Modeled Increment
Concentration = 52.5 ug/m^3

High 2nd-high Modeled WAAQS/NAAQS
Concentration = 59.1 ug/m^3

Figure 7-7
Results of Full-Impact Modeling
for Sulfur Dioxide (24-Hour)

7.8.2 Soils and Vegetation Analysis

CH2M HILL conducted a search for information regarding sensitive soils, sensitive vegetation, and vegetation with commercial or recreational value in the vicinity of the proposed Dry Fork Station.

Based on the most recent U.S. Department of Agriculture (USDA) census, Campbell County had 26,185 acres of cropland in 2002 (USDA, 2002). Crop production consists mostly of hay/forage crops, corn for grain, wheat, oats, and barley. As compared to production in other Wyoming counties, the wheat production in Campbell County ranked 5th, corn and oats production ranked 13th, barley production ranked 16th, and hay/forage crops ranked 18th. Harvested acreages of crops in Campbell County in 2002 were: 2,554 acres of wheat; 22,940 acres of hay/forage crops; and 97 acres of barley. The acreages of corn and oats harvested were not disclosed.

Soil and vegetation classifications within the project area were determined based on existing available data. Dominant vegetation associations characterizing the study area are classified as Wyoming big sagebrush (*Artemesia tridentata Nutt ssp*), mixed grass prairie, and dry land crops (Wyoming GAP, 2005). In addition to the Wyoming big sagebrush community, dominant vegetative species characterizing the mixed grass prairie include buffalo grass (*Buchloe dactyloides*), blue gramma (*Bouteloua gracilis*), sand dropseed (*Sporobolus cryptandrus*), and other plains mixed grass and forb species. None of these species were identified as sensitive.

Soils in the impact area are characterized as plains, dissected plains, and floodplain soil types (USDA, 1979). Dominant plains soils in the study area include the Ustic Haplargids-Ustic Torriorthents associations. These soils are typically fine loams and mesic. The Haplargids occur across broad expanses of the landscape. The Torriorthents occur along eroded drainage ways and around rock outcrops. None of these soils are classified as sensitive by the USDA (USDA, 1979).

Soils within the non-mountainous regions of Wyoming are typically alkaline and would not be sensitive to project impacts (WRDS, 2005). Additionally, depositions should have no adverse effect to vegetation or crops, and may actually have a fertilizing effect (WRDS, 2005).

Of the species identified in the Campbell County vicinity, oats and barley have been identified as crops sensitive to pollutant effects. The exact tolerance of a given crop is dependent on the particular horticultural varieties. Table 7-9 indicates levels of NO_X which have been found to result in plant damage for different species. Photosynthesis is found to be inhibited in alfalfa at 2-hour NO_2 exposures of 4,105 $\mu g/m^3$ (Hill, 1974). In addition, a mixture of approximately 191 $\mu g/m^3$ of NO_X and 265 $\mu g/m^3$ of SO_X administered for 4 hours has been discovered to cause foliar injury to oats (DNR, 2002).

CH2M HILL used the ISC-PRIME model to determine the maximum NO_X and SO_X impacts that would result from the project. The worst-case 3-hour SO_X impact from the proposed unit is 21.1 $\mu g/m^3$ while the worst-case 3-hour NO_X impact is 14.7 $\mu g/m^3$. As a result, the worst-case combined NO_X and SO_X 3-hour impact is 35.8 $\mu g/m^3$. All predicted concentrations are well below those that would be expected to impact vegetation.

TABLE 7-9
Pollutant Effects on Species

Species	Sensitivity Category of Plant	4-hour NO_X Concentrations which Result in 5% Foliar Injury	Worst-Case 3-hour NO_X Concentration
Alfalfa, Oats	Sensitive	3.76-11.28 mg/m^3	
Corn, Wheat	Intermediate	9.4-18.8 mg/m^3	0.0147 mg/m^3
Elder, Ash	Tolerant	> 16.92 mg/m^3	

Based on "Air Quality Criteria for Oxides of Nitrogen", EPA/600/8-91049bF, August, 1993.

The predicted impacts for PM_{10} were below the secondary air quality standards, which are set to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. Predicted impacts for all other regulated pollutants were well below modeling significance levels and monitoring de minimum levels.

7.8.3 Visibility Impairment Analysis

No near-field assessment of Class II area visibility impacts was conducted for the project. There are no Class II "scenic vistas" established by the WDEQ in the vicinity of the proposed project, nor are there established standards for Class II visibility impacts. Additionally, the visibility screening techniques, such as the EPA VISCREEN model, are not adequate to fully assess the impact of the sources proposed for this project.

7.8.4 Ozone

No ambient impact analysis for ozone was conducted for this project. Currently, there are no modeling techniques that are approved for regulatory use for the assessment of ozone impacts from single point sources in rural areas. Also, the estimated emissions of volatile organic compounds (VOC) from the project are well below the 100 tons per year threshold that would require an ambient impact analysis and/or gathering of ambient air quality data for ozone.

7.9 Air Toxics Analysis

7.9.1 Tier 1 Inhalation Risk Analysis

A Tier 1 inhalation risk analysis was conducted for the Dry Fork Station boiler (ES1-01) following the Facility-Specific Air Toxics Risk Assessment guidance developed by EPA (2004). A Tier 1 inhalation risk analysis is a screening-level assessment that incorporates simplified assumptions and default values to allow a simple, health-protective risk estimate to be calculated. Due to the conservative nature of the analysis, the resulting risk estimates are likely to be higher than actual risks. If the facility passes this screening analysis, a risk manager can be reasonably confident that the likelihood for significant risk is low.

7.9.2 Exposure Assessment

Human exposure via inhalation can be assessed by estimating the ambient air concentration of a hazardous air pollutant (HAP). The emissions estimates presented in Section 3 and the ISC-PRIME dispersion modeling results are used to estimate ambient air concentrations at each modeling node (or interpolated nodes), which are, in turn, used to estimate exposure concentrations (ECs). The EC is the ambient air concentration at a receptor location (sometimes called an exposure point). In a Tier 1 analysis it is assumed that the modeled ambient air concentrations and ECs are the same (EPA, 2004). It is also assumed that the exposure estimates derived from a single year's emissions estimates are commonly used to represent a chronic exposure (EPA, 2004)

The modeled ambient air concentration used in the Tier 1 risk analysis is based on the maximum exposed individual (MEI). The MEI is the modeling receptor where the maximum modeled ambient air concentration occurs, regardless of whether an inhalation target is located there under current (or likely future) land use conditions. The MEI provides a conservative estimate of exposure.

The default assumption is that the receptor population is breathing, over a lifetime (70 years by convention), outdoor air continuously at the MEI location. This is believed to be a conservative assumption since indoor air concentrations of air toxics are expected to be the same or lower than the outdoor concentrations (when the indoor concentrations are produced solely by inflow from outside air).

As described above, the MEI ambient air concentration, predicted using the emissions and the ISC-PRIME modeling results, is used as the EC. The EC for each HAP is calculated by multiplying the 1-hour or annual model results obtained with a modeled emission rate of 1 gram per second (g/s) by the hourly or annual emission rates (in g/s). Exposure concentrations (EC_L) for estimating chronic cancer risk are derived using the average annual emission rate assuming the plant is operating at a 100 percent load (Table 7-10). Exposure concentrations (EC_{ST}) for estimating chronic and acute noncancer hazards are derived using the peak hourly emission rate assuming the plant is operating at a 103 percent load (Tables 7-11 and 7-12, respectively).

7.9.3 Toxicity Criteria used in the Tier 1 Risk Analysis

The screening-level toxicity criteria (i.e., chronic and acute dose-response values) published by EPA's Office of Air Quality Planning and Standards Air Toxics Website (http://www.epa.gov/ttn/atw/toxsource/summary.html) are used in this Tier 1 risk analysis:

- Chronic Cancer Toxicity Criteria
  - Inhalation Unit Risk (IUR) values from *Table 1. Prioritized Chronic Dose-Response Values (2/28/05)* are used.
- Chronic Noncancer Toxicity Criteria
  - Reference Concentration (RfC) values from *Table 1. Prioritized Chronic Dose-Response Values (2/28/05)* are used.
- Acute Noncancer Toxicity Criteria
  - Acute Dose-Response Values (AVs) from *Table 2. Acute Dose-Response Values for Screening Risk Assessments (6/02/2005)* are used.

EPA provides specific dose-response recommendations for unspeciated HAP data (EPA, 2004). Therefore the inhalation toxicity criteria for chromium compounds are based on 100 percent chromium VI (Cr^{+6}), mercury compounds are assumed to be 100 percent elemental mercury, and nickel compounds are assumed to be Ni_3S_2 for estimating cancer risk and NiO for estimating chronic noncancer hazard.

7.9.4 Risk Characterization

In the risk characterization, the ECs are combined with the applicable dose-response values to generate the risk and hazard estimates. Estimates of excess cumulative cancer risk, chronic noncancer hazard, and acute noncancer hazard are calculated separately. Background risks and risks from exposure via multiple exposure pathways (e.g., ingestion) are not considered in this Tier 1 risk analysis.

Cancer Risk

Excess lifetime cancer risk is calculated by multiplying the EC and IUR for each HAP using the following equation:

$$\mathbf{Risk = EC_L \times IUR}$$

where:

Risk = excess lifetime cancer risk estimate (expressed as an upper-bound risk of contracting cancer over a lifetime) [unitless];

EC_L = exposure concentration based on a lifetime estimate of continuous inhalation exposure to an individual HAP [$\mu g/m^3$]; and

IUR = inhalation unit risk estimate for that HAP [$1/(\mu g/m^3)$].

A lifetime exposure duration, 70 years by convention, is assumed in this Tier 1 risk analysis. While the modeling results and the emissions estimates are based on a one year duration, the resulting EC_L is assumed to be representative of the entire exposure duration of 70 years (EPA, 2004).

The following equation estimates the predicted incremental excess cancer risk from multiple HAPs:

$$\mathbf{Risk_T = Risk_1 + Risk_2 + ... + Risk_i}$$

where:

$Risk_T$ = total incremental excess cancer risk estimate [unitless]; and
$Risk_i$ = incremental excess cancer risk estimate for the ith HAP [unitless].

This approach is based on an assumption of a linear dose response so that the risks associated with individual chemicals in the mixture are additive.

Estimates of cancer risk are expressed as a statistical probability represented in scientific notation as a negative exponent of 10. For example, an additional upper bound risk of ~~contracting cancer of 1 chance in 1,000,000 (or one additional person in 1,000,000) is written~~

as 1×10^{-6}. Sometimes an exponential notation is used; in this case it would be 1E-06. Because IURs are typically upper-bound estimates, actual risks may be lower than predicted.

As shown in Table 7-10, the $Risk_T$ of 2E-07 is less than lower end of EPA's acceptable risk range of 1E-06, therefore no significant risks are predicted and no further analysis is required.

Chronic Noncancer Hazard

Chronic noncancer hazards for the HAPs are estimated by dividing the exposure concentration (EC) by the reference concentration (RfC) for the HAP to obtain the chronic Hazard Quotient (HQ) using the following equation:

$$\mathbf{HQ = EC_C \div RfC}$$

where:

HQ = chronic hazard quotient for an individual HAP [unitless];

EC_C = exposure concentrations based on an estimate of continuous inhalation exposure to that HAP [$\mu g/m^3$]; and

RfC = noncancer reference concentration for that HAP [$\mu g/m^3$].

Based on the definition of the RfC, a HQ less than or equal to one indicates that adverse noncancer effects are not likely to occur (EPA, 2004).

A chronic cumulative noncancer hazard (the Hazard Index, or HI) is calculated by summing the HQs across all HAPs:

$$\mathbf{HI = HQ_1 + HQ_2 + ... + HQ_i}$$

where

HI = the chronic cumulative hazard index [unitless]; and
HQ = the chronic noncancer hazard quotient for the i_{th} HAP [unitless].

The HI approach is based on the assumption that even when individual HAP concentrations are lower than the corresponding RfCs, some HAPs may work together such that their potential for harm is additive and the combined exposure to the group of HAPs poses greater likelihood of harm. Where the overall HI exceeds one, a more refined analysis is warranted, because interpretation of differences among HQs across HAPs is limited by the fact that the nature of the RfC can vary widely depending on the substance, type of critical effect, and subpopulation exposed. However, as shown in Table 7-11, none of the HQ for individual HAPs, nor the HI, are greater than one, indicating the potential for significant chronic noncancer hazard is low and further analysis is not required.

Acute Noncancer Hazard

Acute noncancer hazard for each HAP are estimated by dividing the short-term exposure concentration (EC_{ST}) by the acute dose-response value (AV) to obtain the acute Hazard Quotient (HQ) using the following equation:

$$\mathbf{HQ_A = EC_{ST} \div AV}$$

where:

HQ_A = the acute hazard quotient for an individual HAP;

EC_{ST} = exposure point concentration based on an estimate of short-term inhalation exposure to that HAP; and

AV = the corresponding acute dose-response value for that HAP.

Available acute dose response values are more diverse than chronic values, because they were developed for different purposes and consider different exposure durations. The characterization of acute risk involves comparing the maximum estimated hourly concentrations with a range of acute dose-response values from sources provided in EPA (2004). Since the EC_{ST} for all the HAPs are lower than the acute benchmarks presented in Table 7-12, meaning the HQ_A is less than one, it is reasonable to conclude that the potential for significant acute risk is low and further analysis is not required.

7.9.5 Uncertainty Discussion

Scientific uncertainty is inherent in the risk assessment process and the numerical estimates of risk and hazard should be placed in context with the uncertainties inherent in the analysis. The purpose of this section is to provide a brief, qualitative discussion of the key areas of uncertainty associated with this Tier 1 risk analysis.

Generally the methods and assumptions used in this Tier 1 risk analysis are conservative and the estimated risks and hazards are intended to be protective of human health. Examples of potential areas of uncertainty are listed below.

- The use of the EC based on the MEI will overestimate risk and hazards for the typical receptor.
- Because individuals do not typically work or leave in the same place for their entire lives, a lifetime (70 year) exposure duration will likely overestimate risk and hazards. And the lack of nearby receptors, even for a 25 or 30 year duration, under current and likely future land use conditions will likely overestimate risks and hazards.
- The use of HAP emission estimates from the proposed boiler are based on industry-wide values rather than facility-specific data and may overestimate risk and hazards.
- Several HAPs lack peer-reviewed dose-response values (see Tables 7-10, 7-11, and 7-12). This may underestimate risks and hazards.

7.9.6 Summary

Further analysis (i.e., performance of a Tier 2 risk analysis) is not necessary because the potential for significant risks and hazards are low based on the results of the Tier 1 risk analysis. The total excess cancer risk estimate of 1E-07 is below the low end of EPA's acceptable risk range (1E-06); the cumulative excess noncancer hazard index is below one; and no acute dose-response values are exceeded by the HAP ECs.

7.10 References

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Table 7-10
Tier 1 Cancer Risk Estimates for Hazardous Air Pollutants
Site-Specific Risk Assessment
Basin Electric Power Cooperative, Dry Fork Station, Unit 1 Boiler (ES1-01)

Analyte	CAS NO.	HAP No.	Emissions[a] [tons/yr]	Maximum Annual Average Exposure Concentration[b] [ug/m3]	Inhalation Unit Risk (IUR)[c] 1/[ug/m3]	Inhalation Unit Risk (IUR) Source[c]	IARC WOE	EPA WOE	Incremental Excess Cancer Risk Estimate [-]	Percent of Total Risk [%]
Biphenyl	92-52-4	19	1.72E-03	4.22E-07				D		
Acenaphthene	83-32-9	187	5.15E-04	1.27E-07				D		
Acenaphthylene	206-96-8	187	2.52E-04	6.21E-08				D		
Anthracene	120-12-7	187	2.12E-04	5.22E-08			3	D		
Benzo(a)anthracene	56-55-3	187	8.08E-05	1.99E-08	1.10E-04	CAL	2A	B2	2.19E-12	<1%
Benzo(a)pyrene	50-32-8	187	3.84E-05	9.44E-09	0.00110	CAL	2A	B2	1.04E-11	<1%
Benzo(b,j,k)fluoranthene	205-99-2	187	1.11E-04	2.73E-08	1.10E-04	CAL	2B	B2	3.01E-12	<1%
Benzo(g,h,i)perylene	191-24-2	187	2.73E-05	6.71E-09			3	D		
Chrysene	218-01-9	187	1.01E-04	2.48E-08	1.10E-05	CAL	3	B2	2.73E-13	<1%
Fluoranthene	206-44-0	187	7.17E-04	1.76E-07			3	D		
Fluorene	86-73-7	187	9.19E-04	2.26E-07			3	D		
Ideno(1,2,3-cd)pyrene	193-39-5	187	6.16E-05	1.52E-08	1.10E-04	CAL	2B	B2	1.67E-12	<1%
Naphthalene	91-20-3	119	1.31E-02	3.23E-06	3.40E-05	CAL		SE	1.10E-10	<1%
Phenanthrene	85-01-8	187	2.73E-03	6.71E-07				D		
Pyrene	129-00-0	187	3.33E-04	8.20E-08				D		
5-Methyl chrysene	3697-24-3	187	2.22E-05	5.46E-09	0.00110	CAL	2B		6.01E-12	<1%
Acetaldehyde	75-07-0	1	5.76E-01	1.42E-04	2.20E-06	IRIS	2B	B2	3.11E-10	<1%
Acetophenone	98-86-2	4	1.51E-02	3.73E-06				D		
Acrolein	107-02-8	6	2.93E-01	7.20E-05			3	Inl		
Benzene	71-43-2	15	1.31E00	3.23E-04	7.80E-06	IRIS	1	CH	2.52E-09	2%
Benzyl chloride	100-44-7	18	7.07E-01	1.74E-04	4.90E-05	CAL	2B	B2	8.52E-09	6%
Bis(2-ethylhexyl)phthalate	117-81-7	20	7.37E-02	1.81E-05	2.40E-06	CAL	2B	B2	4.35E-11	<1%
Bromoform	75-25-2	22	3.94E-02	9.69E-06	1.10E-06	IRIS	3	B2	1.07E-11	<1%
Carbon disulfide	75-15-0	28	1.31E-01	3.23E-05						
2-Chloroacetophenone	532-27-4	36	7.07E-03	1.74E-06						
Chlorobenzene	108-90-7	37	2.22E-02	5.46E-06				D		
Chloroform	67-66-3	39	5.96E-02	1.47E-05			2B	LH		
Cumene	98-82-8	46	5.35E-03	1.32E-06				Inl		
Cyanide	57-12-5	180	2.52E00	6.21E-04				D		
2,4-Dinitrotoluene	121-14-2	71	2.83E-04	6.95E-08	8.90E-05	CAL	2B	B2	6.19E-12	<1%
Dimethyl sulfate	77-78-1		4.85E-02	1.19E-05						
Ethyl benzene	100-41-4	77	9.49E-02	2.33E-05				D		
Ethyl chloride	75-00-3	79	4.24E-02	1.04E-05						
Ethylene dichloride	107-06-2	81	4.04E-02	9.94E-06	2.60E-05	IRIS	2B	B2	2.58E-10	<1%
Ethylene dibromide	106-93-4	80	1.21E-03	2.98E-07	6.00E-04	IRIS	2A	LH	1.79E-10	<1%
Formaldehyde	50-00-0	87	2.42E-01	5.96E-05	5.50E-09	EPA OAQPS	2A	B1	3.28E-13	<1%
Hexane	110-54-3	95	6.77E-02	1.66E-05						
Isophorone	78-59-1	100	5.86E-01	1.44E-04	2.70E-07	Conv. Oral		C	3.89E-11	<1%
Methyl bromide	74-83-9	105	1.62E-01	3.97E-05				D		
Methyl chloride	74-87-3	106	5.35E-01	1.32E-04				Inl		
Methyl ethyl ketone	78-93-3	108	3.94E-01	9.69E-05				Inl		
Methyl hydrazine	60-34-4		1.72E-01	4.22E-05						
Methyl methacrylate	80-62-6	113	2.02E-02	4.97E-06				E		
Methyl tert butyl ether	1634-04-4	114	3.53E-02	8.69E-06	2.60E-07	CAL			2.26E-12	<1%
Methylene chloride	75-09-2	116	2.93E-01	7.20E-05	4.70E-07	IRIS	2B	B2	3.39E-11	<1%
Phenol	108-95-2	130	1.62E-02	3.97E-06			3	Inl		
Propionaldehyde	123-38-6		3.84E-01	9.44E-05						
Tetrachloroethylene	127-18-4	150	4.34E-02	1.07E-05	5.90E-06	CAL	2A	B2-C	6.30E-11	<1%
Toluene	108-88-3	152	2.42E-01	5.96E-05			3	D		
1,1,1-Trichloroethane	79-00-5	158	2.02E-02	4.97E-06	1.60E-05	IRIS	3	C	7.95E-11	<1%
Styrene	100-42-5	146	2.52E-02	6.21E-06			2B			
Xylenes	1330-20-7	169	3.74E-02	9.19E-06				Inl		
Vinyl acetate	108-05-4	165	7.67E-03	1.89E-06			2B			
Hydrochloric Acid	7647-01-0	97	1.38E01	3.40E-03			3			
Hydrofluoric Acid	7664-39-3	98	1.12E01	2.76E-03						
Antimony	7440-36-0	173	1.34E-02	3.29E-06						
Arsenic	7440-38-2	174	1.34E-02	3.29E-06	0.00430	IRIS	1	A	1.41E-08	10%
Beryllium	7440-41-7	175	4.01E-03	9.87E-07	0.00240	IRIS	1	LH	2.37E-09	2%
Cadmium	7440-43-9	176	2.67E-03	6.58E-07	0.00180	IRIS	1	B1	1.18E-09	<1%
Chromium	18540-29-9	177	4.01E-02	9.87E-06	0.0120	IRIS	1	CH	1.18E-07	80%
Cobalt	7440-48-4	178	2.67E-02	6.58E-06						
Lead	7439-92-1	182	2.67E-02	6.58E-06			2B	B2		
Manganese	7439-96-5	183	1.07E-01	2.63E-05				D		
Mercury	7439-97-6	184	4.68E-02	1.15E-05				D		
Molybdenum	7439-98-7		1.34E-02	3.29E-06						
Nickel	7440-02-0	186	5.35E-02	1.32E-05			2B	A		
Selenium	7782-49-2	189	1.34E-01	3.29E-05				D		
Total Incremental Excess Cancer Risk Estimate:									1E-07	100%

Notes:

a : Emissions based on the plant operating at a 103 percent load.

b : The maximum exposure concentration was estimated using ISC modeled maximum predicted annual impact (100 percent load) based on a 1 g/s unit emission rate (ug/m3): 0.00855

c : Source : Office of Air Quality Planning and Standards. Air Toxics Website (http://www.epa.gov/ttn/atw/toxsource/summary.html). Table 1. Prioritized Chronic Dose-Response Values (2/28/05).

CAS NO. = Chemical Abstracts Services number for the compound.

HAP NO. = Position of the compound on the HAP list in the Clean Air Act (112[b][2]). "999" denotes substances under consideration for listing.

IARC WOE = weight-of-evidence for carcinogenicity in humans (1 - carcinogenic; 2A - probably carcinogenic; 2B - possibly carcinogenic; 3 - not classifiable; 4 - probably not carcinogenic).

EPA WOE = weight-of-evidence for carcinogenicity under the 1986 EPA cancer guidelines, as superseded for specific compounds by the 1999 interim guidelines (1986 guidelines: A - human carcinogen; B1 - probable carcinogen, limited human evidence; B2 - probable carcinogen, sufficient evidence in animals; C - possible human carcinogen; D - not classifiable E - evidence of noncarcinogenicity. 1999 guidelines: CH - carcinogenic to humans; LH - likely to be carcinogenic; SE - suggestive evidence for carcinogenicity; Inl - inadequate information to determine carcinogenicity; NL - not likely to be carcinogenic).

IRIS : USEPA's Integrated Risk Information System Unit Risk Estimate (URE).

CAL : California Environmental Protection Agency Carcinogenic Unit Risk Estimate (URE).

EPA OAQPS : US EPA Office of Air Quality Planning and Standards.

Conv. Oral : Extrapolated from Oral URE.

Blank = IUR not available.

Table 7-11
Tier 1 Chronic Noncancer Risk Estimates for Hazardous Air Pollutants
Site-Specific Risk Assessment
Basin Electric Power Cooperative, Dry Fork Station, Unit 1 Boiler (ES1-01)

Analyte	CAS NO.	HAP No.	Emissions[a] [lbs/hr]	Continuous Exposure Concentration[b] [ug/m3]	Continuous Exposure Concentration[b] [mg/m3]	Reference Concentration (RFC)[c] [mg/m3]	Reference Concentration (RFC) Source[c]	Hazard Quotient [-]	Percent of HI [%]
Biphenyl	92-52-4	19	4.14E-04	6.19E-05	6.19E-08				
Acenaphthene	83-32-9	187	1.24E-04	1.86E-05	1.86E-08				
Acenaphthylene	206-96-8	187	6.09E-05	9.10E-06	9.10E-09				
Anthracene	120-12-7	187	5.12E-05	7.65E-06	7.65E-09				
Benzo(a)anthracene	56-55-3	187	1.95E-05	2.91E-06	2.91E-09				
Benzo(a)pyrene	50-32-8	187	9.26E-06	1.38E-06	1.38E-09				
Benzo(b,j,k)fluoranthene	205-99-2	187	2.68E-05	4.00E-06	4.00E-09				
Benzo(g,h,i)perylene	191-24-2	187	6.58E-06	9.83E-07	9.83E-10				
Chrysene	218-01-9	187	2.44E-05	3.64E-06	3.64E-09				
Fluoranthene	206-44-0	187	1.73E-04	2.58E-05	2.58E-08				
Fluorene	86-73-7	187	2.22E-04	3.31E-05	3.31E-08				
Ideno(1,2,3-cd)pyrene	193-39-5	187	1.49E-05	2.22E-06	2.22E-09				
Naphthalene	91-20-3	119	3.17E-03	4.73E-04	4.73E-07	0.00300	IRIS	1.58E-04	<1%
Phenanthrene	85-01-8	187	6.58E-04	9.83E-05	9.83E-08				
Pyrene	129-00-0	187	8.04E-05	1.20E-05	1.20E-08				
5-Methyl chrysene	3697-24-3	187	5.36E-06	8.01E-07	8.01E-10				
Acetaldehyde	75-07-0	1	1.39E-01	0.0208	2.08E-05	0.00900	IRIS	0.00231	<1%
Acetophenone	98-86-2	4	3.65E-03	5.46E-04	5.46E-07				
Acrolein	107-02-8	6	7.07E-02	0.01056	1.06E-05	2.00E-05	IRIS	0.528	71%
Benzene	71-43-2	15	3.17E-01	0.0473	4.73E-05	0.0300	IRIS	0.00158	<1%
Benzyl chloride	100-44-7	18	1.71E-01	0.0255	2.55E-05				
Bis(2-ethylhexyl)phthalate	117-81-7	20	1.78E-02	0.00266	2.66E-06	0.0100	P-CAL	2.66E-04	<1%
Bromoform	75-25-2	22	9.50E-03	1.42E-03	1.42E-06				
Carbon disulfide	75-15-0	28	3.17E-02	0.00473	4.73E-06	0.700	IRIS	6.76E-06	<1%
2-Chloroacetophenone	532-27-4	36	1.71E-03	2.55E-04	2.55E-07	3.00E-05	IRIS	0.00849	1%
Chlorobenzene	108-90-7	37	5.36E-03	8.01E-04	8.01E-07	1	CAL	8.01E-07	<1%
Chloroform	67-66-3	39	1.44E-02	0.00215	2.15E-06	0.0980	ATSDR	2.19E-05	<1%
Cumene	98-82-8	46	1.29E-03	1.93E-04	1.93E-07	0.400	IRIS	4.82E-07	<1%
Cyanide	57-12-5	180	6.09E-01	0.0910	9.10E-05				
2,4-Dinitrotoluene	121-14-2	71	6.82E-05	1.02E-05	1.02E-08	0.00700	P-CAL	1.46E-06	<1%
Dimethyl sulfate	77-78-1		1.17E-02	0.00175	1.75E-06				
Ethyl benzene	100-41-4	77	2.29E-02	0.00342	3.42E-06	1	IRIS	3.42E-06	<1%
Ethyl chloride	75-00-3	79	1.02E-02	0.00153	1.53E-06	10	IRIS	1.53E-07	<1%
Ethylene dichloride	107-06-2	81	9.75E-03	1.46E-03	1.46E-06	2.40	ATSDR	6.07E-07	<1%
Ethylene dibromide	106-93-4	80	2.92E-04	4.37E-05	4.37E-08	0.00900	IRIS	4.85E-06	<1%
Formaldehyde	50-00-0	87	5.85E-02	0.00874	8.74E-06	0.00980	ATSDR	8.92E-04	<1%
Hexane	110-54-3	95	1.63E-02	0.00244	2.44E-06	0.200	IRIS	1.22E-05	<1%
Isophorone	78-59-1	100	1.41E-01	0.0211	2.11E-05	2	CAL	1.06E-05	<1%
Methyl bromide	74-83-9	105	3.90E-02	0.00582	5.82E-06	0.00500	IRIS	1.16E-03	<1%
Methyl chloride	74-87-3	106	1.29E-01	0.0193	1.93E-05	0.0900	IRIS	2.14E-04	<1%
Methyl ethyl ketone	78-93-3	108	9.50E-02	0.01420	1.42E-05	5	IRIS	2.84E-06	<1%
Methyl hydrazine	60-34-4		4.14E-02	0.00619	6.19E-06				
Methyl methacrylate	80-62-6	113	4.87E-03	7.28E-04	7.28E-07	0.700	IRIS	1.04E-06	<1%
Methyl tert butyl ether	1634-04-4	114	8.53E-03	1.27E-03	1.27E-06	3	IRIS	4.25E-07	<1%
Methylene chloride	75-09-2	116	7.07E-02	0.01056	1.06E-05	1	ATSDR	1.06E-05	<1%
Phenol	108-95-2	130	3.90E-03	5.82E-04	5.82E-07	0.200	CAL	2.91E-06	<1%
Propionaldehyde	123-38-6		9.26E-02	0.01383	1.38E-05				
Tetrachloroethylene	127-18-4	150	1.05E-02	0.00157	1.57E-06	0.270	ATSDR	5.80E-06	<1%
Toluene	108-88-3	152	5.85E-02	0.00874	8.74E-06	0.400	IRIS	2.18E-05	<1%
1,1,1-Trichloroethane	79-00-5	158	4.87E-03	7.28E-04	7.28E-07	0.400	P-CAL	1.82E-06	<1%
Styrene	100-42-5	146	6.09E-03	9.10E-04	9.10E-07	1	IRIS	9.10E-07	<1%
Xylenes	1330-20-7	169	9.02E-03	1.35E-03	1.35E-06	0.100	IRIS	1.35E-05	<1%
Vinyl acetate	108-05-4	165	1.85E-03	2.77E-04	2.77E-07	0.200	IRIS	1.38E-06	<1%
Hydrochloric Acid	7647-01-0	97	3.23E00	0.483	4.83E-04	0.0200	IRIS	0.0241	3%
Hydrofluoric Acid	7664-39-3	98	2.62E00	0.392	3.92E-04	0.0140	CAL	0.0280	4%
Antimony	7440-36-0	173	3.23E-03	4.82E-04	4.82E-07				
Arsenic	7440-38-2	174	3.23E-03	4.82E-04	4.82E-07	3.00E-05	CAL	0.0161	2%
Beryllium	7440-41-7	175	9.68E-04	1.45E-04	1.45E-07	2.00E-05	IRIS	0.00723	<1%
Cadmium	7440-43-9	176	6.45E-04	9.64E-05	9.64E-08	2.00E-05	CAL	0.00482	<1%
Chromium	18540-29-9	177	6.45E-03	9.64E-04	9.64E-07	1.00E-04	IRIS	0.00964	1%
Cobalt	7440-48-4	178	6.45E-03	9.64E-04	9.64E-07	1.00E-04	ATSDR	0.00964	1%
Lead	7439-92-1	182	6.45E-03	9.64E-04	9.64E-07	0.00150	EPA OAQPS	6.43E-04	<1%
Manganese	7439-96-5	183	2.58E-02	0.00386	3.86E-06	5.00E-05	IRIS	0.0771	10%
Mercury	7439-97-6	184	1.13E-02	1.69E-03	1.69E-06	3.00E-04	IRIS	0.00562	<1%
Molybdenum	7439-98-7		3.23E-03	4.82E-04	4.82E-07				
Nickel	7440-02-0	186	1.29E-02	0.00193	1.93E-06	9.00E-05	D-ATSDR	0.0214	3%
Selenium	7782-49-2	189	3.23E-02	0.00482	4.82E-06	0.0200	CAL	2.41E-04	<1%
								0.7	100%

Notes:

a : Emissions based on the plant operating at a 100 percent load.

b : The maximum exposure concentration was estimated using ISC modeled maximum predicted 1 hour impact for a 103 percent load based on a 1 g/s unit emission rate (ug/m3): 1.18553

c : Source : Office of Air Quality Planning and Standards. Air Toxics Website (http://www.epa.gov/ttn/atw/toxsource/summary.html). Table 1. Prioritized Chronic Dose-Response Values (2/28/05).

CAS NO. = Chemical Abstracts Services number for the compound.

HAP NO. = Position of the compound on the HAP list in the Clean Air Act (112[b][2]). "999" denotes substances under consideration for listing.

IARC WOE = International Agency for Research on Cancer weight-of-evidence for carcinogenicity in humans (1 - carcinogenic; 2A - probably carcinogenic; 2B - possibly carcinogenic; 3 - not classifiable; 4 - probably not carcinogenic).

EPA WOE = US Environmental Protection Agency weight-of-evidence for carcinogenicity under the 1986 EPA cancer guidelines, as superseded for specific compounds by the 1999 interim guidelines (1986 guidelines: A - human carcinogen; B1 - probable carcinogen, limited human evidence; B2 - probable carcinogen, sufficient evidence in animals; C - possible human carcinogen; D - not classifiable E - evidence of noncarcinogenicity. 1999 guidelines: CH - carcinogenic to humans; LH - likely to be carcinogenic; SE - suggestive evidence for carcinogenicity; Inl - inadequate information to determine carcinogenicity; NL - not likely to be carcinogenic).

IRIS : US EPA Integrated Risk Information System.

CAL : California Environmental Protection Agency Reference Exposure Level (REL).

EPA OAQPS : US EPA Office of Air Quality Planning and Standards.

ATDSR : US Agency for Toxic Substances and Disease Registry

P-CAL : Proposed California Environmental Protection Agency Reference Exposure Level (REL).

D-ATSDR : US Agency for Toxic Substances and Disease Registry. Draft Mininum Risk Level (MRL).

Blank = RFC not available.

Table 7-12

Tier 1 Acute Noncancer Risk Estimates for Hazardous Air Pollutants

Site-Specific Risk Assessment

Basin Electric Power Cooperative, Dry Fork Station, Unit 1 Boiler (ES1-01)

						Acute Dose-Response Value (AV)[c]											
Analyte	CAS NO.	HAP No.	Emissions[a] [lbs/hr]	Maximum Short-Term Exposure Concentration[b] [ug/m3]	Maximum Short-Term Exposure Concentration[b] [mg/m3]	AEGL-1 (1-h) [mg/m3]	AEGL-1 (8-h) [mg/m3]	AEGL-2 (1-h) [mg/m3]	AEGL-2 (8-h) [mg/m3]	ERPG-1 [mg/m3]	ERPG-2 [mg/m3]	MRL [mg/m3]	REL [mg/m3]	IDLH/10 [mg/m3]	TEEL-0 [mg/m3]	TEEL-1 [mg/m3]	Exposure Concentration (EC_{ST}) Exceeds AV?
Hydrofluoric Acid	7664-39-3	98	2.62E00	3.92E-01	3.92E-04	0.820	0.820	2	9.80	1.60	16	0.250	0.240	2.50			No
Antimony	7440-36-0	173	3.23E-03	4.82E-04	4.82E-07									5			No
Arsenic	7440-38-2	174	3.23E-03	4.82E-04	4.82E-07								0.190	0.500			No
Beryllium	7440-41-7	175	9.68E-04	1.45E-04	1.45E-07						0.250			0.400			No
Cadmium	7440-43-9	176	6.45E-04	9.64E-05	9.64E-08									0.900			No
Chromium	18540-29-9	177	6.45E-03	9.64E-04	9.64E-07									1.50			No
Cobalt	7440-48-4	178	6.45E-03	9.64E-04	9.64E-07									2			No
Lead	7439-92-1	182	6.45E-03	9.64E-04	9.64E-07									1			No
Manganese	7439-96-5	183	2.58E-02	3.86E-03	3.86E-06									5			No
Mercury	7439-97-6	184	1.13E-02	1.69E-03	1.69E-06						2.10		0.180				No
Molybdenum	7439-98-7		3.23E-03	4.82E-04	4.82E-07												No
Nickel	7440-02-0	186	1.29E-02	1.93E-03	1.93E-06								0.600	1			No
Selenium	7782-49-2	189	3.23E-02	4.82E-03	4.82E-06									0.100			No

Notes:

a : Emissions based on the plant operating at a 100 percent load.

b : The maximum exposure concentration was estimated using ISC modeled maximum predicted 1 hour impact based on a 1 g/s unit emission rate (ug/m3): **1.18553**

c : Source : Office of Air Quality Planning and Standards. Air Toxics Website (http://www.epa.gov/ttn/atw/toxsource/summary.html). Table 2. Acute Dose-Response Values for Screening Risk Assessments (6/02/2005).

AEGL = Acute exposure guideline levels for mild effects (AEGL-1) and moderate effects (AEGL-2) for 1- and 8-hour exposures. Superscripts indicate the AEGL's status: f = final, i=interim, and p=proposed.

ERPG = US DOE Emergency Removal Program guidelines for mild or transient effects (ERPG-1) and irreversible or serious effects (ERPG-2) for 1-hour exposures.

MRL = ATSDR minumum risk levels for no adverse effects for 1 to 14-day exposures.

REL = California EPA reference exposure level for no adverse effects. Most, but not all, RELs are for 1-hour exposures.

IDLH/10 = One-tenth of levels determined by NIOSH to be imminently dangerous to life and health, approximately comparable to mild effects levels for 1-hour exposures.

TEEL = US DOE Temporary emergency exposure limits for no effects (TEEL-0) and mild, transient effects (TEEL-1) for 1-hour exposures. TEELs are derived according to a tiered, formula-like methodology, and do not undergo peer review. They are not recommended as the basis for regulatory desision-making, and are shown here only to inform situations where acute values from other sources are not available.

Table 7-12

Tier 1 Acute Noncancer Risk Estimates for Hazardous Air Pollutants

Site-Specific Risk Assessment

Basin Electric Power Cooperative, Dry Fork Station, Unit 1 Boiler (ES1-01)

						Acute Dose-Response Value (AV)[c]											
Analyte	CAS NO.	HAP No.	Emissions[a] [lbs/hr]	Maximum Short-Term Exposure Concentration[b] [ug/m3]	Maximum Short-Term Exposure Concentration[b] [mg/m3]	AEGL-1 (1-h) [mg/m3]	AEGL-1 (8-h) [mg/m3]	AEGL-2 (1-h) [mg/m3]	AEGL-2 (8-h) [mg/m3]	ERPG-1 [mg/m3]	ERPG-2 [mg/m3]	MRL [mg/m3]	REL [mg/m3]	IDLH/10 [mg/m3]	TEEL-0 [mg/m3]	TEEL-1 [mg/m3]	Exposure Concentration (EC_{ST}) Exceeds AV?
Biphenyl	92-52-4	19	4.14E-04	6.19E-05	6.19E-08										1	3.90	No
Acenaphthene	83-32-9	187	1.24E-04	1.86E-05	1.86E-08										0.400	1.30	No
Acenaphthylene			6.09E-05	9.10E-06	9.10E-09												No
Anthracene	120-12-7	187	5.12E-05	7.65E-06	7.65E-09										2	6	No
Benzo(a)anthracene	56-55-3	187	1.95E-05	2.91E-06	2.91E-09										0.100	0.300	No
Benzo(a)pyrene	50-32-8	187	9.26E-06	1.38E-06	1.38E-09										0.200	0.600	No
Benzo(b,j,k)fluoranthene	205-99-2	187	2.68E-05	4.00E-06	4.00E-09										0.200	0.600	No
Benzo(g,h,i)perylene	191-24-2	187	6.58E-06	9.83E-07	9.83E-10										1	3	No
Chrysene	218-01-9	187	2.44E-05	3.64E-06	3.64E-09										0.200	0.600	No
Fluoranthene	206-44-0	187	1.73E-04	2.58E-05	2.58E-08										0.500	0.150	No
Fluorene	86-73-7	187	2.22E-04	3.31E-05	3.31E-08										7.50	25	No
Ideno(1,2,3-cd)pyrene	193-39-5	187	1.49E-05	2.22E-06	2.22E-09										0.150	0.500	No
Naphthalene	91-20-3	119	3.17E-03	4.73E-04	4.73E-07									13			No
Phenanthrene	85-01-8	187	6.58E-04	9.83E-05	9.83E-08										0.400	1	No
Pyrene	129-00-0	187	8.04E-05	1.20E-05	1.20E-08										15	15	No
5-Methyl chrysene			5.36E-06	8.01E-07	8.01E-10												No
Acetaldehyde	75-07-0	1	1.39E-01	2.08E-02	2.08E-05					18	36			36			No
Acetophenone	98-86-2	4	3.65E-03	5.46E-04	5.46E-07										1	3	No
Acrolein	107-02-8	6	7.07E-02	1.06E-02	1.06E-05	0.690	0.690	0.230	0.230	0.230	1.10	0.110	0.190	0.460			No
Benzene	71-43-2	15	3.17E-01	4.73E-02	4.73E-05	17	29	26	64	16	48	0.160	1.30	16			No
Benzyl chloride	100-44-7	18	1.71E-01	2.55E-02	2.55E-05					5.20	52		0.240	5.20			No
Bis(2-ethylhexyl)phthalate	117-81-7	20	1.78E-02	2.66E-03	2.66E-06										5	1	No
Bromoform	75-25-2	22	9.50E-03	1.42E-03	1.42E-06									88			No
Carbon disulfide	75-15-0	28	3.17E-02	4.73E-03	4.73E-06	12	6.20	5	16	3.10	16		6.20	16			No
2-Chloroacetophenone	532-27-4	36	1.71E-03	2.55E-04	2.55E-07												No
Chlorobenzene	108-90-7	37	5.36E-03	8.01E-04	8.01E-07									46			No
Chloroform	67-66-3	39	1.44E-02	2.15E-03	2.15E-06			31	14		24	0.490	0.150	24			No
Cumene	98-82-8	46	1.29E-03	1.93E-04	1.93E-07									44			No
Cyanide	57-12-5	180	6.09E-01	9.10E-02	9.10E-05									2.50			No
2,4-Dinitrotoluene	121-14-2	71	6.82E-05	1.02E-05	1.02E-08									5			No
Dimethyl sulfate	77-78-1		1.17E-02	1.75E-03	1.75E-06												No
Ethyl benzene	100-41-4	77	2.29E-02	3.42E-03	3.42E-06									35			No
Ethyl chloride	75-00-3	79	1.02E-02	1.53E-03	1.53E-06							4		1			No
Ethylene dichloride	107-06-2	81	9.75E-03	1.46E-03	1.46E-06					2	81			2			No
Ethylene dibromide	106-93-4	80	2.92E-04	4.37E-05	4.37E-08									77			No
Formaldehyde	50-00-0	87	5.85E-02	8.74E-03	8.74E-06	1.10	1.10	17	17	1.20	12	0.490	0.940	2.50			No
Hexane	110-54-3	95	1.63E-02	2.44E-03	2.44E-06									39			No
Isophorone	78-59-1	100	1.41E-01	2.11E-02	2.11E-05										28	28	No
Methyl bromide	74-83-9	105	3.90E-02	5.82E-03	5.82E-06			82	26		19	0.190	3.90	97			No
Methyl chloride	74-87-3	106	1.29E-01	1.93E-02	1.93E-05						83	1		41			No
Methyl ethyl ketone	78-93-3	108	9.50E-02	1.42E-02	1.42E-05	59	59	8	5				13				No
Methyl hydrazine	60-34-4		4.14E-02	6.19E-03	6.19E-06												No
Methyl methacrylate	80-62-6	113	4.87E-03	7.28E-04	7.28E-07	7	7	49	2					41			No
Methyl tert butyl ether	1634-04-4	114	8.53E-03	1.27E-03	1.27E-06							7.20					No
Methylene chloride	75-09-2	116	7.07E-02	1.06E-02	1.06E-05					69	26	2.10	14	8			No
Phenol	108-95-2	130	3.90E-03	5.82E-04	5.82E-07	58	24	89	46	38	19		5.80	96			No
Propionaldehyde	123-38-6		9.26E-02	1.38E-02	1.38E-05												No
Tetrachloroethylene	127-18-4	150	1.05E-02	1.57E-03	1.57E-06	24	24	16	55	68	14	1.40	2	1			No
Toluene	108-88-3	152	5.85E-02	8.74E-03	8.74E-06	75	75	19	19	19	11	3.80	37	19			No
1,1,1-Trichloroethane	79-00-5	158	4.87E-03	7.28E-04	7.28E-07									55			No
Styrene	100-42-5	146	6.09E-03	9.10E-04	9.10E-07	85	85	55	55	21	11		21	3			No
Xylenes	1330-20-7	169	9.02E-03	1.35E-03	1.35E-06	56	56	17	17			4.30	22	39			No
Vinyl acetate	108-05-4	165	1.85E-03	2.77E-04	2.77E-07					18	26						No
Hydrochloric Acid	7647-01-0	97	3.23E00	4.83E-01	4.83E-04	2.70	2.70	33	16	4.50	3		2.10	7.50			No

Section 8

Far-Field Modeling

SECTION 8.0

Far-Field Air Quality Impact Analysis

Basin Electric Power Cooperative (BEPC) proposes to construct the Dry Fork Station Project near Gillette, Wyoming. The proposed power plant would include one pulverized coal (PC) boiler that would be capable of generating a maximum 422 MW (gross) of electrical power. Representatives of BEPC and CH2M HILL met with key personnel from the Wyoming Department of Environmental Quality (WDEQ) and the National Park Service (NPS) on August 4, 2005 to discuss the proposed CALPUFF modeling protocol for the project. Changes to the protocol that were suggested by the WDEQ and the NPS were incorporated into the final protocol for the project titled *Protocol for a CALPUFF Modeling Analysis of the Dry Fork Station Project (Northeast Wyoming Generation Project)*(CH2M HILL, 2005). This section presents a detailed description of the far-field (CALPUFF) air quality impact analysis that was conducted for the project pursuant to that protocol.

8.1 Introduction

The proposed Dry Fork Station Project would be located to the northeast of the City of Gillette in Campbell County, Wyoming. The proposed location is approximately four miles to the northeast of the Gillette-Campbell County Airport. Within 250 kilometers (km) of the project, there are three areas in South Dakota and Montana that are classified as Class I areas for the protection of air quality. These areas include Wind Cave and Badlands National Parks in South Dakota, which are located approximately 180 and 220 kilometers (km), respectively, to the east-southeast. The Northern Cheyenne Indian Reservation is located approximately 135 km to the northwest in southern Montana. CH2M HILL used the CALPUFF modeling system to assess the potential air quality impacts at these three Class I areas.

The CALPUFF analysis included an assessment of visibility, atmospheric deposition, and criteria pollutant impacts at each Class I area. Our analyses was performed based on the final modeling protocol for the project, and general guidance found in the following documents: *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report* (FLAG, 2000), and *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998).

The visibility analysis assessed the potential Class I impacts from the proposed project only, in accordance with the WDEQ regulations governing Prevention of Significant Deterioration (PSD) projects. Page 6-64 of Chapter 6, Section 4 of the Air Quality Division (AQD) regulations includes the following: "The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the facility or modification and general commercial, residential, industrial, and other growth associated with the facility or modification." (WDEQ, 2003).

The NPS has established Deposition Analysis Thresholds (DAT) for Eastern and Western regions of the United States. A DAT is the amount of deposition within an area below which the impacts from a proposed project would be considered insignificant. The DAT for Western areas is 0.005 kg/ha/yr for total nitrogen and also for total sulfur (NPS, 2002). Modeled sulfur and nitrogen deposition from the project at each Class I area was compared to the DAT for the western region. Table 8-1 lists the Class I modeling significance levels and PSD increments that apply to the project.

At the request of the NPS, visibility and criteria pollutant impacts were also assessed at Devil's Tower National Monument in Wyoming. Because Devil's Tower is a Class II area, the criteria pollutant impacts were compared to Class II modeling significance levels.

TABLE 8-1
Class I Modeling Significance Levels and Increments

Averaging Period/ Pollutant	Class I Modeling Significance Level ($\mu g/m^3$)*	Class I PSD Increment ($\mu g/m^3$)
Annual NO_2	0.1	2.5
3-hour SO_2	1.0	25**
24-hour SO_2	0.2	5**
Annual SO_2	0.1	2
24-hour PM_{10}	0.3	8**
Annual PM_{10}	0.2	4

* Proposed by U.S. EPA, Federal Register: July 1996 (Vol. 61, Number 142), Proposed Rules, pg. 38249-344.

** Not to be exceeded more than once per year.

Notes:

$\mu g/m^3$ = micrograms per cubic meter
NO_2 = Nitrogen dioxide
NS = No standard
PM_{10} = Particulate matter less than 10 microns
PSD = Prevention of Significant Deterioration
SO_2 = Sulfur dioxide

8.2 Model Selection

Class I areas affected by the project are located more than 50 km from the proposed source. Workgroups that represent the interests of the Federal Land Managers (FLM) in the PSD permitting process (IWAQM, FLAG) recommend that a "far-field analysis" of the effect of a proposed source on air quality and air quality-related values (AQRV) be performed for sources located more than 50 km from affected areas. CH2M HILL used the EPA CALPUFF modeling system, as recommended by the EPA and the FLM for far-field analyses, to obtain predicted impacts. The CALPUFF modeling system includes the CALMET meteorological model, a Gaussian puff dispersion model (CALPUFF) with algorithms for chemical transformation and deposition, and a postprocessor capable of calculating concentrations, visibility impacts, and deposition (CALPOST). The CALPUFF modeling system was applied in a full, refined mode rather than a screening mode.

CH2M HILL used the EPA-approved versions of the CALPUFF modeling system preprocessors and models. Specifically, we used the Beta-test versions that are currently available on the Earth Tech website (http://www.calgrid.net/calpuff/calpuff1.htm). The latest versions of the primary models include the following:

- CALMET Version 5.53a, Level 040716
- CALPUFF Version 5.711a, Level 040716
- CALPOST Version 5.51, Level 030709

8.3 CALMET

The application of the CALMET model for the production of meteorological input to the CALPUFF model is described in this section.

8.3.1 Dimensions of the CALMET Domain

CH2M HILL used the CALMET model to generate three-dimensional wind fields and other meteorological parameters suitable for use by the CALPUFF model. A modeling domain was established to encompass higher terrain west of Gillette and the Class I areas of interest. The domain covers a region approximately 672 km by 472 km with a grid resolution of 4 km.

CH2M HILL used a Lambert Conformal Conic (LCC) map projection for the analysis due to the large extent of the domain. Figure 8-1 shows the CALMET/CALPUFF modeling domain and provides the key parameters for the LCC map projection.

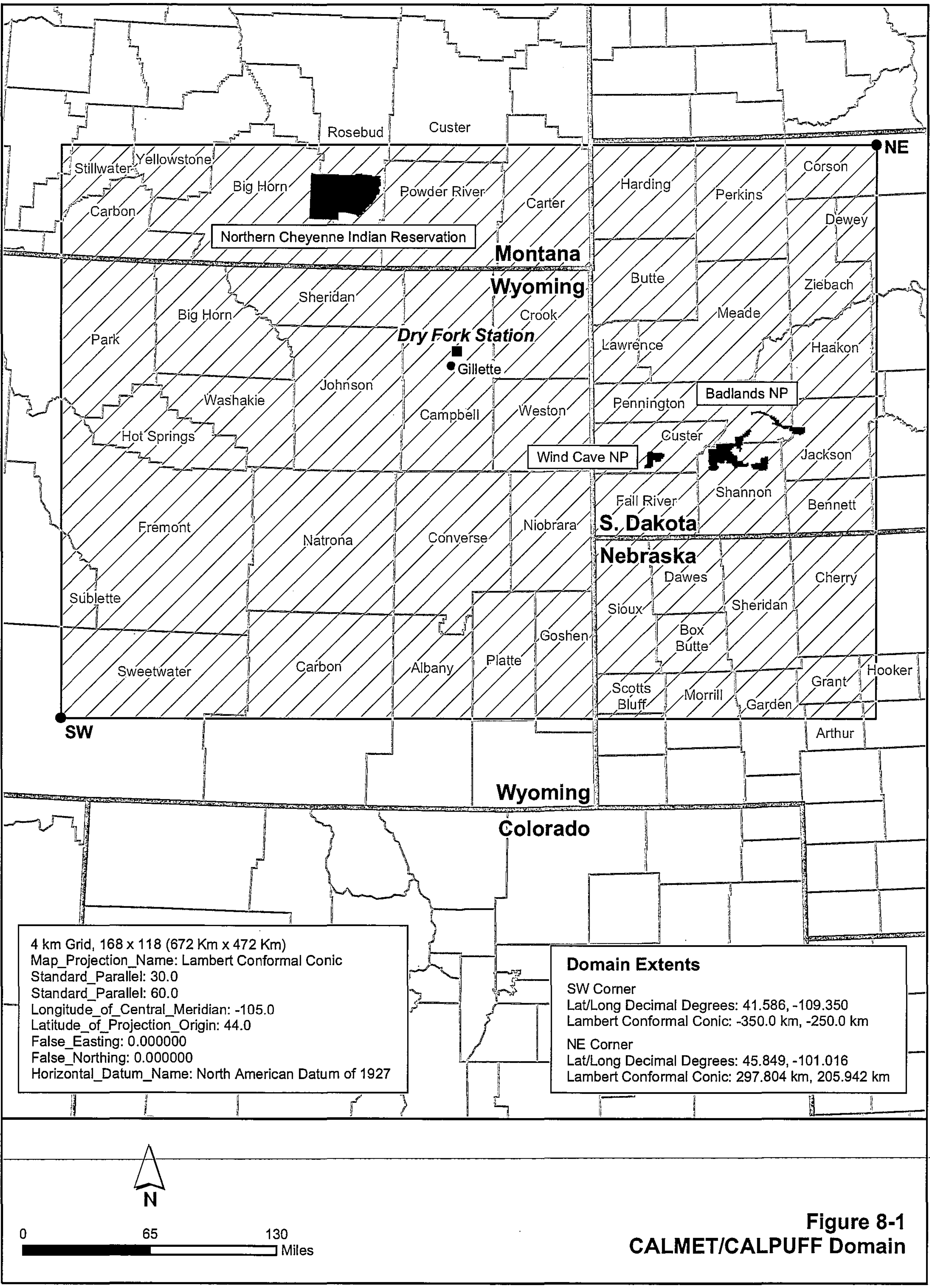
The default technical options listed in Appendix B of the IWAQM Phase 2 report were used for CALMET. User-specified model options were determined by CH2M HILL's professional staff to produce the most realistic wind field. Vertical resolution of the wind field included nine layers, with vertical cell face heights as follows (in meters):

- 0, 20, 50, 100, 250, 500, 750, 1000, 1500, 3500

8.3.2 CALMET Input Data

8.3.2.1 Mesoscale Prognostic Data

CH2M HILL ran the CALMET model to produce three years of analysis: 2001, 2002 and 2003. For 2001, CH2M HILL used data at 36-km resolution that were obtained from the contractor (Alpine Geophysics) who developed the nationwide data for the EPA. For 2002, nationwide 36-km MM5 data, developed for the Visibility Improvement State and Tribal Association of the Southeast (VISTAS), were obtained from the same EPA contractor. Data for 2003 were also obtained from Alpine Geophysics. These 2003 data, also at 36-km resolution, were developed by the Wisconsin Department of Natural Resources, the Illinois Environmental Protection Agency, and the Lake Michigan Air Directors Consortium. These three datasets were chosen because they are current and because they have all been evaluated for quality. The MM data were used as input to CALMET as the "initial guess" wind field. The initial guess field was adjusted by CALMET for local terrain and land use effects to generate a Step 1 wind field, and then further refined using local surface observations to create a final Step 2 wind field.



4 km Grid, 168 x 118 (672 Km x 472 Km)
Map_Projection_Name: Lambert Conformal Conic
Standard_Parallel: 30.0
Standard_Parallel: 60.0
Longitude_of_Central_Meridian: -105.0
Latitude_of_Projection_Origin: 44.0
False_Easting: 0.000000
False_Northing: 0.000000
Horizontal_Datum_Name: North American Datum of 1927

Domain Extents

SW Corner
Lat/Long Decimal Degrees: 41.586, -109.350
Lambert Conformal Conic: -350.0 km, -250.0 km

NE Corner
Lat/Long Decimal Degrees: 45.849, -101.016
Lambert Conformal Conic: 297.804 km, 205.942 km

Figure 8-1
CALMET/CALPUFF Domain

8.3.2.2 Surface Data

Surface data for 2001-2003 were obtained from the National Climatic Data Center (NCDC). CH2M HILL used all available stations from the National Weather Service's (NWS) Automated Surface Observing System (ASOS) network within the modeling domain that contained a high percentage of valid data for a given year.

The surface data were obtained from NCDC in abbreviated DATSAV3 format. A conversion routine available from the Earth Tech website was used to convert the DATSAV3 files to CD-144 format for input to the SMERGE preprocessor and CALMET. Figure 8-2 shows the locations of the surface stations that were used for the 2001-2003 analyses.

8.3.2.3 Upper-Air Data

Upper-air observations from Rapid City, South Dakota were input to CALMET to adjust the initial guess wind field. The Rapid City station is located between the source and two of the Class I areas in question, and therefore represented critical data to add to CALMET. Other upper-air stations such as Riverton, Wyoming and North Platte, Nebraska are located off of the modeling domain or near the edge of the domain, far removed from the source and Class I areas, and were not used in the analysis. Rapid City data for 2001, 2002, and 2003 in FSL format were obtained and processed through the READ62 processor.

8.3.2.4 Geophysical Data

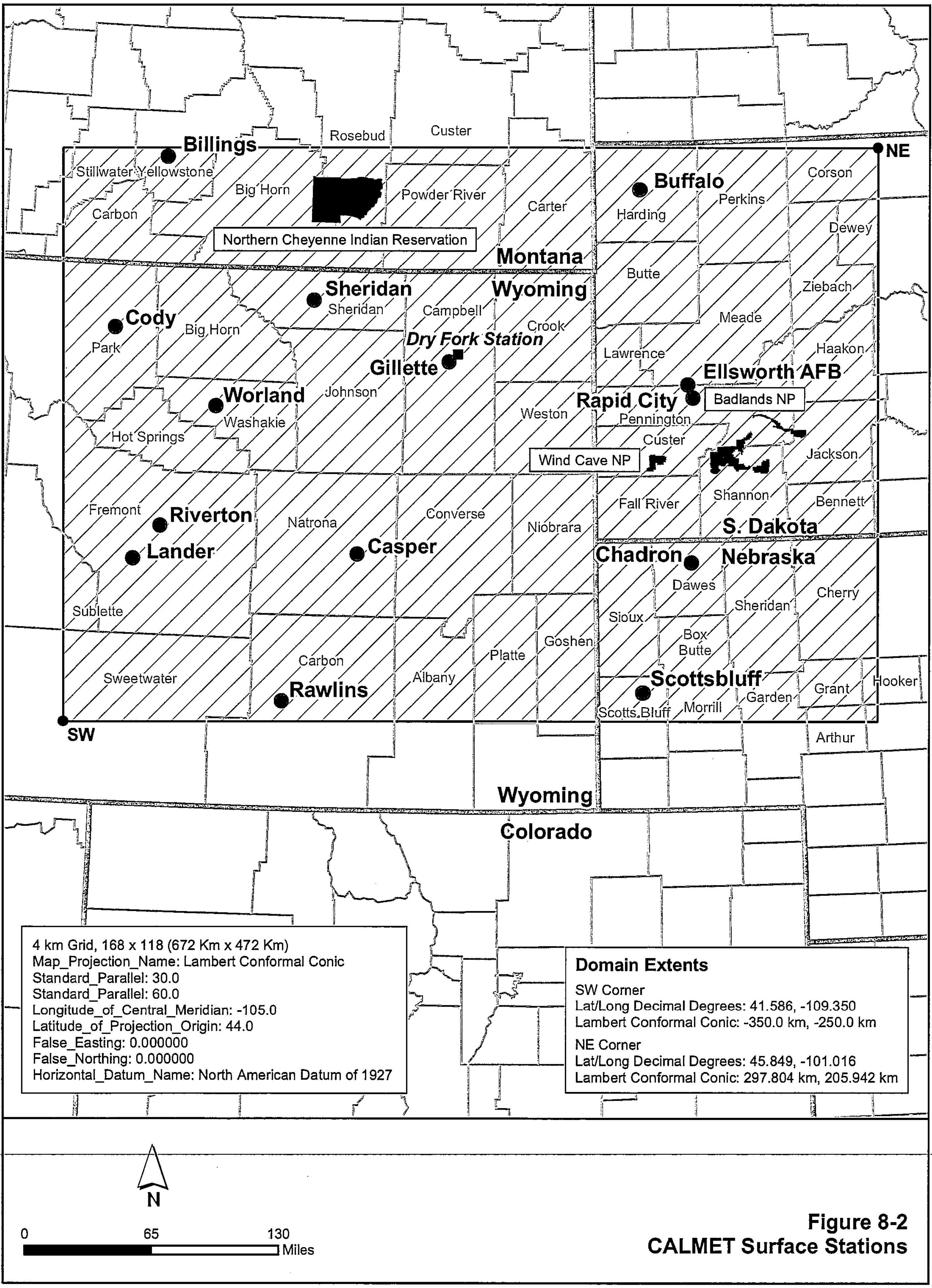
Land use and terrain data to construct the GEO.DAT input to CALMET were obtained from the U.S. Geological Survey (USGS). Land use data were obtained in Composite Theme Grid (CTG) format from the USGS, and the Level I USGS land use categories were mapped into the 14 primary CALMET land use categories. Surface properties such as albedo, Bowen ratio, roughness length, and leaf area index were computed from the land use values. Terrain data were taken from USGS 1-degree Digital Elevation Model (DEM) data, which are primarily derived from USGS 1:250,000 scale topographic maps. A value of 31 (shrub and brush rangeland) was input to the MAKEGEO.INP file for the IMISS parameter. With the IMISS parameter, whenever land use data are missing for a grid cell in the domain, IMISS is attributed to that cell. A figure showing the land use for the domain is included in Appendix H.

8.3.2.5 Precipitation Data

CH2M HILL obtained from NCDC all available TD-3240 precipitation files within the modeling domain. The TD-3240 files were processed through PEXTRACT and PMERGE to prepare the data for input to CALMET. For 2001 and 2002, a total of 62 precipitation stations were input to CALMET. For 2003, 63 stations were used. Figure 8-3 shows the precipitation stations within the modeling domain.

8.3.3 Validation of CALMET Wind Field

CH2M HILL used the CalDESK data display and analysis system (v2.9, Enviromodeling Ltda.) to view plots of wind vectors and other meteorological parameters to evaluate the CALMET wind fields. We used observed weather conditions, as depicted in surface and upper-air weather maps from the National Oceanic and Atmospheric Administration (NOAA) Central Library U.S. Daily Weather Maps Project (http://docs.lib.noaa.gov/rescue/dwm/data_rescue_daily_weather_maps.html), to compare to the CalDESK displays.



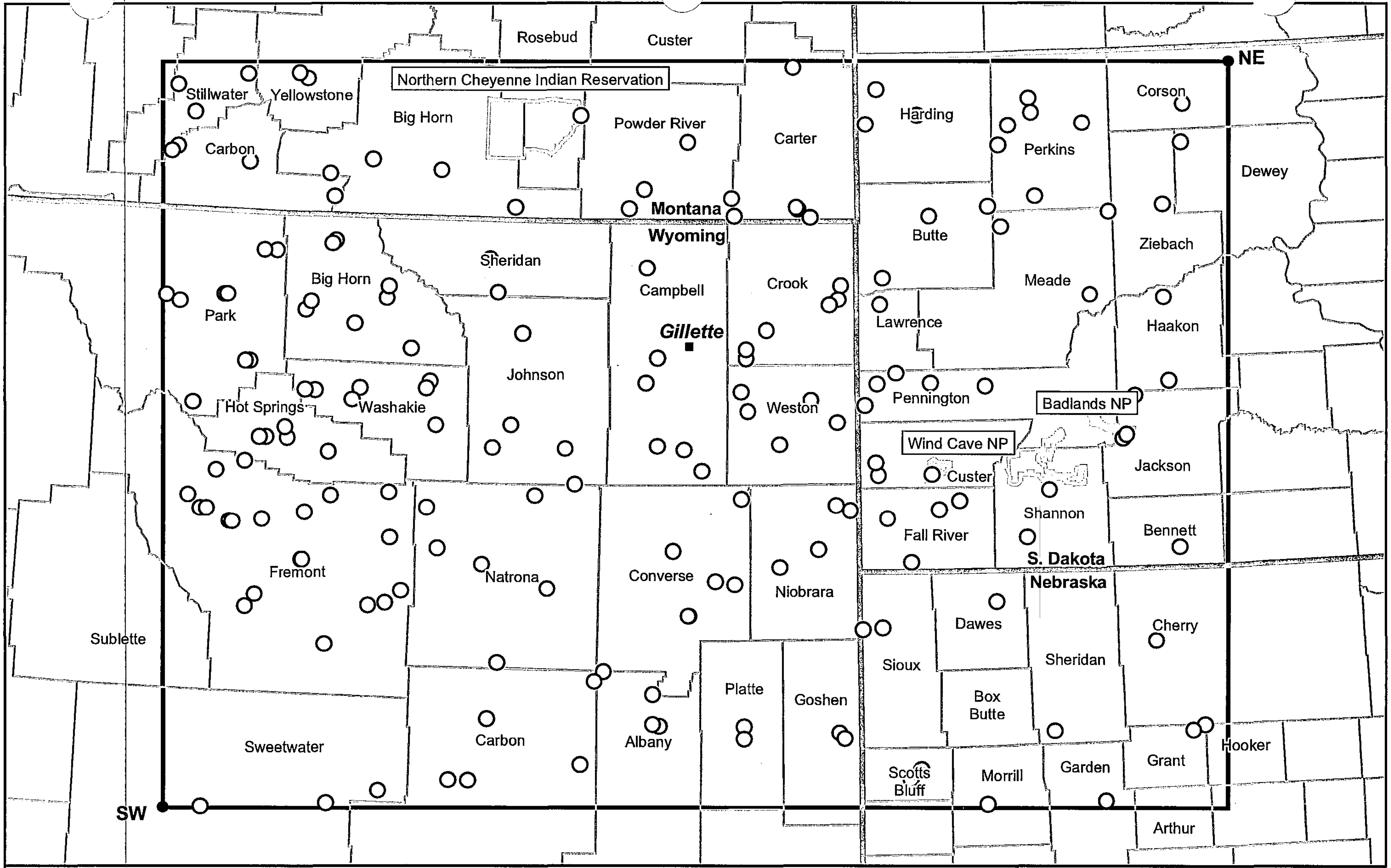
4 km Grid, 168 x 118 (672 Km x 472 Km)
Map_Projection_Name: Lambert Conformal Conic
Standard_Parallel: 30.0
Standard_Parallel: 60.0
Longitude_of_Central_Meridian: -105.0
Latitude_of_Projection_Origin: 44.0
False_Easting: 0.000000
False_Northing: 0.000000
Horizontal_Datum_Name: North American Datum of 1927

Domain Extents

SW Corner
Lat/Long Decimal Degrees: 41.586, -109.350
Lambert Conformal Conic: -350.0 km, -250.0 km

NE Corner
Lat/Long Decimal Degrees: 45.849, -101.016
Lambert Conformal Conic: 297.804 km, 205.942 km

Figure 8-2
CALMET Surface Stations



N

Domain Extents

SW Corner
Lat/Long Decimal Degrees: 41.586, -109.350
Lambert Conformal Conic: -350.0 km, -250.0 km

NE Corner
Lat/Long Decimal Degrees: 45.849, -101.016
Lambert Conformal Conic: 297.804 km, 205.942 km

Figure 8-3
Precipitation Stations for
Montana, Nebraska, S. Dakota and Wyoming

8.3.3.1 2001

The first day we examined for 2001 was January 3. This day was chosen because the surface map showed that high pressure was dominating the area of the modeling domain, and nighttime drainage winds from the higher terrain would be expected. This was reflected in the CalDESK views for the evening hours, which showed winds flowing down the slopes of the Black Hills and the Bighorn and Wind River Mountains. The 500-millibar map showed that the upper-level, high-pressure area was centered on the west coast at 7:00 A.M. EST, with clockwise flow bringing northwest to southeast wind aloft. This flow was reflected in the highest layer of the wind field during this timeframe. July 4 was another day that was dominated by high pressure at the surface, as shown in the NOAA weather maps. Pronounced drainage winds were in evidence on the CalDESK views for the evening hours of July 4, with the flows changing directions with sunrise.

8.3.3.2 2002

For 2002, December 20 was chosen as a day that should show strong downslope flows at night due to high pressure that was in place at the surface according to the NOAA weather map. An examination of the CalDESK views showed that drainage flows were indeed in place. The upper-level ridge was positioned so that winds in the western part of the domain should be west to east, and winds in the eastern part of the domain would be more from the northwest. This was reflected very well in the CalDESK views for the highest layer in the wind field. CH2M HILL chose September 16 as a warm-weather day that should show strong upslope/downslope flows due to high pressure at the surface and an overall quiet weather pattern. Nighttime CalDESK views of the wind field showed pronounced downslope winds that reversed direction (especially near the Bighorns) with sunrise and through the morning hours.

8.3.3.3 2003

For 2003, the NOAA surface weather map for January 6 showed a strong high pressure area centered just to the west of the modeling domain. Nighttime winds during this period, as shown in the CalDESK views, displayed pronounced downslope flows that persisted through mid-morning. The upper-level ridge on this day was positioned so that winds at the highest level of the domain should be blowing nearly north to south, with somewhat lower wind speeds in the east and southeast part of the domain. This wind speed and wind direction pattern was reflected in the CalDESK views for the highest layer in the wind field. CH2M HILL chose July 10 as a warm-weather day that should show strong upslope/downslope flows due to high pressure at the surface and an overall quiet weather pattern. Nighttime CalDESK views of the wind field showed pronounced, light downslope winds that changed direction with sunrise. The upper-level ridge on this day was positioned to the southwest of the modeling domain in a position that would produce upper-level winds blowing from northwest to southeast. This pattern was shown in the CalDESK views for the highest layer in the wind field.

Based on our review of these test days, we conclude that the use of MM5 and other meteorological data processed through CALMET produced wind fields that are expected ~~and reasonable for the modeling domain.~~

8.4 CALPUFF

CH2M HILL drove the CALPUFF model with the meteorological wind fields output from CALMET over the modeling domain described earlier. Source emission rates, exhaust parameters, background ozone concentrations, and technical options used within CALPUFF are described below.

8.4.1 Source Emission Rates and Exhaust Parameters

Emissions and exhaust parameters for the proposed boiler stack were derived from engineering estimates for peak load conditions for the boiler. Particulate emissions from the proposed boiler for the project were speciated between filterable particulate (fine PM_{10}/soil), primary emissions of condensable hydrogen fluoride (HF) and hydrogen chloride (HCL), primary sulfate, elemental carbon due to loss on ignition (LOI, 0.5 perecent of filterable), and organic carbon condensables. Primary sulfate emissions consisted of ammonium sulfate and sulfuric acid mist. This speciation allowed for the consideration within the visibility analysis of the different scattering efficiencies of the various species. This apportionment is important because some particles, especially elemental carbon (EC) particles, have a greater impact on visibility. For example, EC particles have a light extinction efficiency of 10 inverse megameters per micrograms per cubic meter ($Mm^{-1}/\mu g/m^3$), while sulfate particles have an extinction efficiency of 3.0 $Mm^{-1}/\mu g/m^3$. Detailed emissions calculations and stack parameters are presented in Attachment 3. Table 8-2 presents the stack parameters modeled for the boiler stack, and Table 8-3 presents the emission rates.

Because the WDEQ intends to establish a 3-hour SO_2 emission limit within the permit for the project (but no 24-hour limit), emission rates for 24-hour SO_2 modeling in CALPUFF were based on the proposed 3-hour SO_2 emission limit. The NO_x emission rate in CALPUFF was based on the expected 30-day NO_x limit that will be established in the permit. WDEQ does not intend to establish a short-term emission limit for NO_x. Detailed emissions calculations and exhaust parameters are presented in Appendix B.

TABLE 8-2
Boiler Stack Parameters

Source	Stack Height: ft (m)	Stack Diameter: ft (m)	Exit Velocity: ft/s (m/s)	Exhaust Temperature: °F (K)
Boiler Stack	500 (152.4)	19.5 (5.94)	84.15 (25.65)	170 (350)

Notes:
°F = Degrees Fahrenheit
ft = Feet
ft/s = Feet per second
K = Kelvin
m = Meters
m/s = Meters per second

TABLE 8-3
Boiler Emissions

Source	NO_x Emission Rate (lb/hr)	SO_2 Emission Rate (lb/hr)	PM_{10} Emission Rate (lb/hr)*	SO_4 Emission Rate (lb/hr)	Organic Carbon (lb/hr)
Boiler Stack	266.1	380.1	51.5	10.4	1.9

Notes:
* Includes filterable particulate (fine PM_{10}/soil), condensable HF and HCL, and elemental carbon (LOI)
lb/hr = pounds per hour
NO_x = Nitrogen oxides
PM_{10} = Particulate matter less than 10 microns
SO_2 = Sulfur dioxide
SO_4 = Sulfate

8.4.2 Technical Options

CH2M HILL drove the CALPUFF model with the meteorological output from CALMET over the modeling domain described earlier. To evaluate the impacts from the proposed project, only the emissions from the proposed Dry Fork Station boiler were modeled.

CH2M HILL used the default CALPUFF technical options that are listed in the IWAQM Phase 2 guidance document and the current sample CALPUFF input file from the Earth Tech website. For wet and dry deposition, CH2M HILL used the CALPUFF default values for particle size parameters and scavenging coefficients for sulfate and nitrate particles. For PM_{10} particles, CH2M HILL used data for baghouse control from Table 1.1-6 from AP-42 Chapter 1.1 (Bituminous and Subbituminous Coal Combustion). The data in the table yield an average particle size diameter of 2.5 microns and a standard deviation of 5.

8.4.3 Background Ozone and Ammonia

Hourly ozone data were input to CALPUFF for chemical transformation. These data were compiled from two stations, Thunder Basin National Grasslands in Wyoming and the Robbinsdale site near Rapid City, South Dakota. The Thunder Basin visibility and air quality monitoring station is located approximately 32 miles north of Gillette. The site is maintained by the WDEQ, and became operational in May 2001. A digital camera, transmissometer, ambient nephelometer, meteorology equipment, ozone analyzer, oxides of nitrogen analyzer and an IMPROVE aerosol sampler are located at this site. The Robbinsdale site is maintained by the South Dakota Department of Environment and Natural Resources. This station collects hourly ozone readings during the "ozone season", which in this case is May through September. Data were available for 2002-2003. CH2M HILL compiled all available hourly data from these two sites into a model-ready ozone input file.

For periods of missing hourly ozone data, the chemical transformation relied on monthly default values that were input to CALPUFF. We determined the monthly default values by calculating monthly average concentrations from all available data, which included data ~~from a National Park Service (NPS) station at Badlands National Park that began operating~~ in August of 2003. The highest monthly average for a given month that was calculated from the available stations was input to CALPUFF as the default value for that month. The calculated monthly values were as follows:

January: 30 ppb
February: 36 ppb
March: 40 ppb
April: 41 ppb
May: 46 ppb
June: 47 ppb
July: 49 ppb
August: 50 ppb
September: 39 ppb
October: 35 ppb
November: 31 ppb
December: 30 ppb

A constant background ammonia concentration of 10 ppb was input to CALPUFF for chemical transformation with the MESOPUFF II chemical transformation scheme.

8.4.4 CALPUFF Receptor Grids

Discrete receptors for the CALPUFF modeling were placed at uniform spacing along the boundary and in the interior of each area of concern. As recommended by the NPS, receptors were taken from the NPS database for Class I area modeling. A copy of this database, along with a conversion routine for various coordinate systems, *NPS Convert Class I Areas*, was provided to CH2M HILL by the NPS. The NPS conversion routine was used to convert all latitude/longitude coordinates to LCC coordinates, including receptors, meteorological stations, and source locations. Because the NPS database does not include the Northern Cheyenne Indian Reservation, those receptors were taken from a sample CALPUFF input file provided by WDEQ that used the same map projection as was used for the Dry Fork Station Project domain. The total number of receptors for Badlands and Wind Cave was 100 and 189, respectively. The number of receptors for Northern Cheyenne was 462.

Receptors for Devils Tower National Monument were placed at 1-km spacing along the boundary and the interior of the monument grounds, resulting in a total of 17 receptors. These receptors were converted to LCC coordinates using the NPS conversion routine.

8.5 CALPOST

8.5.1 Visibility

Visibility impacts were estimated through the use of the modeled concentrations produced by CALPUFF and hourly relative humidity data from the CALMET output, both within the CALPOST postprocessor. CALPOST calculates the percent change in extinction attributable to the project emissions as compared to the natural background extinction in the areas of concern.

The percent change in light extinction (Δ) is calculated using:

$$\Delta = \frac{\Delta b}{b_{back}} * 100$$

Where Δb is the incremental increase in light extinction due to the project emissions and b_{back} is the background light extinction under natural conditions.

The organic carbon condensable fraction was estimated from organic Hazardous Air Pollutants (HAPs) that have boiling temperatures less than 300°F. This approach served to capture all organics that will condense at ambient temperatures below the stack exhaust temperature.

The incremental increases in light extinction from the project were determined from the modeled concentrations of all pollutants that could potentially degrade visibility: nitrate, sulfate, and particulate (filterable and condensable). Particulate emissions from the proposed unit included filterable particulate (fine PM_{10}/soil), condensable HF and HCL, primary sulfate, and elemental carbon (LOI). Organic carbon condensables were modeled as a separate species. Because the total PM_{10} emission rate included the EC emissions, the POSTUTIL program was used to split the PM_{10} concentrations into "soil" and EC for subsequent consideration in the CALPOST program. This allowed for the consideration of the differing light extinction coefficients for ordinary particulate matter (1.0) vs. EC (10).

Because their scattering effects are dependent on relative humidity, sulfates and nitrates are referred to as hygroscopic species. Relative humidity for the consideration of extinction from the hygroscopic particles was calculated on an hourly basis from data in the CALMET file, and then averaged for each 24-hour period. This is Method 2 in CALPOST, which is the recommended method in FLAG for a refined CALPUFF visibility analysis. Background extinction (b_{back}) due to natural aerosols for the areas of concern was calculated within CALPOST using the equation:

$$b_{back} = b_{hygro} \times f(RH) + b_{NonHygro} + Rayleigh$$

Where b_{hygro}, $b_{NonHygro}$, and Rayleigh scattering components are provided in Appendix 2.B of the FLAG Phase I report. As shown in the FLAG report, the values for b_{hygro} (0.6 Mm^{-1}), $b_{NonHygro}$, (4.5 Mm^{-1}), and Rayleigh scattering (10 Mm^{-1}) are the same for Wind Cave and Badlands. These values are the current FLAG-recommended estimates of "natural background" for all western areas. Although such values are not provided for Northern Cheyenne Indian Reservation, CH2M HILL assumed that the background extinction provided within the FLAG document for the Western Class I areas will also apply to the Northern Cheyenne Indian Reservation.

Relative humidity for the consideration of extinction from hygroscopic particles was calculated on an hourly basis from data in the CALMET files. This approach represents Method 2 in CALPOST, which is the recommended method in the FLAG document for a refined CALPUFF visibility analysis. The cap on relative humidity in CALPOST was set at 95 percent. This cap was suggested by the NPS at the August 4, 2005 meeting described earlier.

Table 8-4 presents a summary of the raw visibility results.

TABLE 8-4
Raw Visibility Results

Area	Maximum Modeled Light Extinction	Number of Days with Percentage Change > 5%	Number of Days with Percentage Change > 10%
2001			
Wind Cave NP	8.3%	2	0
Badlands NP	4.4%	0	0
Northern Cheyenne Indian Reservation	11.6%	2	1
2002			
Wind Cave NP	8.8%	1	0
Badlands NP	5.6%	1	0
Northern Cheyenne Indian Reservation	5.7%	2	0
2003			
Wind Cave NP	8.0%	3	0
Badlands NP	5.01%	1	0
Northern Cheyenne Indian Reservation	51.8%	1	1

Notes:
NP = National Park

8.5.2 Refined Visibility Results

The raw visibility results using Method 2 were derived from a calculation of percentage light extinction that uses "natural" background as the denominator. The FLAG document defines natural conditions as "[c]onditions substantially unaltered by humans or human activities. As applied in the context of visibility, natural conditions include naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration." Aerosols that occur naturally in the ambient air affect background visibility under natural conditions. Natural background visibility is also affected by water in various physical states that naturally occur in the ambient air in the form of humidity, clouds, and fog or in the form of precipitation as snow or rain.

The recommended FLAG approach provides a method of adjustment of natural background visibility for one form of atmospheric water expressed as relative humidity through the growth of hygroscopic particles. However, FLAG does not provide a method of adjusting natural background visibility for atmospheric water naturally occurring in the other physical states. Therefore, to fully account for the impact on natural visibility due to atmospheric water in all forms and not just relative humidity, CH2M HILL used a method to adjust for background extinction caused by condensed water as well.

The NPS operates the IMPROVE transmissometer at Badlands NP to measure actual background visibility. This transmissometer at Badlands NP measures actual atmospheric light extinction over a path length of approximately 4.15 km. This measurement includes the effects of both natural and human-caused conditions. Because only natural conditions are to be considered in the estimation of natural background, CH2M HILL devised a method to remove the effect of human-caused visibility impairment from the transmissometer data.

The NPS publishes, on the CSU IMPROVE web site for each of the IMPROVE transmissometer sites, an 8-year visibility trends analysis of the 10th, 50th, and 90th percentile averages of reconstructed light extinction and the light scattering of the major aerosol types. The 10th percentile days are the best in terms of visibility and the 90th are the worst. The reconstruction of these light extinction estimates by NPS accounts only for the effect of aerosols measured in the atmosphere at the IMPROVE site and specifically excludes any effect on visibility due to water.

The 1999 90th percentile reconstructed light extinction and the light scattering for each IMPROVE site are reported in the web document titled BEXT_1yr_Mar2002_TXT.htm. The year 1999 is the most recent year available for reconstructed light extinction. For Badlands for 1999, the 90th percentile value reported by NPS for reconstructed visibility impairment is 45.23 Mm^{-1}. This represents the highest average reconstructed light extinction at the Badlands IMPROVE site in 1999 due to measured aerosols that are both natural and human caused.

Hourly transmissometer light extinction readings at Badlands NP for 1999 range from 942 Mm^{-1} (indicating total blockage of the 4.15-km transmissometer light path) to 8 Mm^{-1}. Generally the highest light obscuration events occur when condensed water is present in the atmosphere in the form of clouds, fog, snow, or rain. In order to be conservative, a light extinction level of 50 Mm^{-1} was chosen as the possible transition between aerosol-dominated and condensed water-dominated light extinction at Badlands NP.

CH2M HILL obtained hourly Badlands transmissometer data for any days for which the raw Method 2 result is greater than or equal to 5 percent at Badlands or Wind Cave National Parks. Background light extinction was determined for each hour by examining the Badlands transmissometer data for that hour. If the measured light extinction was 50 Mm^{-1} or more, indicating possible condensed water dominated light extinction, the transmissometer reading was used for background for that hour if other evidence indicates natural obscuration. If the measured extinction is less than 50 Mm^{-1}, indicating aerosol dominated light extinction; the light extinction value calculated using the FLAG-prescribed equation and prescribed background above was used. The transmissometer readings were used along with surface meteorological observations from Rapid City and other available data to verify that visibility obscuration events at Badlands or Wind Cave also occurred at roughly the same time at Rapid City indicating the meteorological events were regional in scale.

For the Northern Cheyenne Indian Reservation, CH2M HILL used the observed visual range at the nearest National Weather Service (NWS) surface station (Sheridan, Wyoming) in a similar fashion to substitute observed visual range as background for obscured conditions. Observations at the NWS station at Billings, Montana and other available data were used to verify that visibility obscuration events at Sheridan and Billings occurred at roughly the same time.

The natural background adjustment described above is similar to the approach used in Montana for the Roundup Power Plant (RPP) project. This is described in a letter from the Department of Interior to the Montana Department of Environmental Quality (Manson, 2003). The letter says "[I]t is our interpretation that 'natural conditions' include significant meteorological events such as fog, precipitation, or naturally occurring haze. Based on the information received and subsequent analysis of that data and the policy guidance, I have concluded that on those days when RPP [Roundup Power Plant] was shown in the original analysis to have resulted in a visibility extinction of 5 percent or more a weather event was the most significant source of the visibility extinction and not the RPP emissions."

The following discussion examines each instance that the raw 24-hour visibility result exceeded 5 percent. Detailed data sheets that summarize observed weather and visibility for these days are presented in Appendix H.

March 22, 2001: Wind Cave NP

The raw, modeled 24-hour average visibility result for this day was 8.34 percent. Transmissometer readings at nearby Badlands NP and surface meteorological observations at Rapid City indicate that pronounced natural obscuration was in place for most of the day. Observed weather at Rapid City included 19 hours of rain, mist, or fog. Visibility at Rapid City was reduced to 0.2 mile for nine hours during the 24-hour period. Hourly transmissometer readings at Badlands were greater than 50 Mm^{-1} for 20 hours of the day, and for 13 of these hours the reading was 942 Mm^{-1}, which indicates total obscuration along the 4.15 km optical path of the instrument. Using the transmissometer data as a substitute for natural background when the hourly reading exceeded 50 Mm^{-1}, the predicted 24-hour visibility impact is reduced to 0.3 percent.

March 23, 2001: Wind Cave NP

For this day, the raw, modeled visibility impact was 5.37 percent. Transmissometer readings at nearby Badlands NP and surface meteorological observations at Rapid City indicate that the weather event of March 22 continued into the first half of March 23. Observed weather at Rapid City included 11 hours of fog, rain, mist, snow, or drizzle. Visibility at Rapid City was reduced to 0.2 mile for four hours during the first half of the day. Hourly transmissometer readings at Badlands were greater than 50 Mm^{-1} for the entire day, with five of these readings at 942 Mm^{-1} (total obscuration). Using the transmissometer reading as a substitute for natural background when the hour exceeded 50 Mm^{-1}, the predicted 24-hour visibility impact is reduced to 0.3 percent.

February 23, 2001: Northern Cheyenne Indian Reservation

The raw, modeled visibility result for this day was 11.6 percent. Surface meteorological observations at Billings, Montana and Sheridan, Wyoming indicate that a weather event is affecting the area that includes strong natural obscuration. Observed weather at Billings included 11 hours of mist, and observed weather at Sheridan included 16 hours of mist or fog. Visibility was reduced at Billings for most of the day, while visibility at Sheridan was reduced for the entire period, with a minimum of 0.2 miles for three hours. To arrive at a predicted visibility impact that accounts for natural obscuration, CH2M HILL took the measured visual range from the nearest NWS surface station (Sheridan) for hours that included obscuring weather, and converted the visual range to units of Mm^{-1}. Using the calculated extinction for the obscured hours as a substitute for natural background, the predicted 24-hour visibility impact is reduced to 0.1 percent.

April 6, 2001: Northern Cheyenne Indian Reservation

The raw, modeled visibility result for this day was 9.4 percent. Surface meteorological observations include three to four hours of thunderstorms and rain at Billings, Montana and Sheridan, Wyoming. Visibility (visual range) readings do not fall below the instrument maximum reading of 10 km at either location, but one cannot conclude from this that visibility was not reduced to some degree because the visual range on a clear day would be much higher than 10 km. A visual range of just 10 km is equivalent to an atmospheric light extinction of 391 Mm^{-1} which is well into the light scattering range due to condensed water. Therefore, even if the actual visual range is somewhat above 10 km, this still indicates natural obscuration from condensed water is occurring. If the visual range for the hour at Sheridan that included rain showers is converted to units of Mm^{-1} and substituted for natural background, the predicted 24-hour visibility impact is reduced to less than 5 percent.

October 26, 2002: Wind Cave NP

The raw, modeled visibility result for this day was 8.8 percent. Transmissometer readings at nearby Badlands NP and surface meteorological observations at Rapid City and Ellsworth AFB near Rapid City indicate that pronounced natural obscuration was in place for more than half of the day. Surface weather observations at Rapid City were missing for the first 10 hours of the day, but the weather station at nearby Ellsworth AFB observed fog for four hours during the morning. Rapid City recorded two hours of mist after the station came back on line at 1100. Visibility at Ellsworth was reduced to 0.2 mile (0.32 km) or less for three hours from 0800-1000. This 0.32 km visual range is equivalent to a light extinction of 12,225 Mm^{-1}. Hourly transmissometer readings at Badlands were greater than 50 Mm^{-1} for the entire day, with three of these readings at 942 Mm^{-1}, which indicates total obscuration of the 4.15-km transmissometer. Using the transmissometer reading as a substitute for natural background when the hourly reading exceeded 50 Mm^{-1}, the predicted 24-hour visibility impact is reduced to 0.5 percent.

October 26, 2002: Badlands NP

The raw, modeled visibility result for this day was 5.6 percent. This predicted impact occurred on the same day as the October 26, 2002 impact predicted at Wind Cave NP (described above). Using Badlands transmissometer data as a substitute for natural background when the hourly reading exceeded 50 Mm^{-1}, the predicted 24-hour visibility impact is reduced to 0.3 percent.

October 27, 2002: Northern Cheyenne Indian Reservation

The raw, modeled visibility result for this day was 5.7 percent. There were no observations of "present weather"or reduced visibility at Billings, Montana or Sheridan, Wyoming on this day. Therefore, there is no evidence of natural obscuration due to condensed water or means to further refine the result for this day.

March 23, 2002: Northern Cheyenne Indian Reservation

The raw, modeled visibility result for this day was 5.3 percent. Surface meteorological observations at Billings, Montana and Sheridan, Wyoming indicate that a weather event is affecting the area that includes strong natural obscuration. Observed weather at Billings included four hours of snow or mist, and observed weather at Sheridan included seven hours of snow or mist. Visibility was reduced at Billings for the later part of the day, and for most of the morning and the later part of the day at Sheridan. To arrive at a predicted visibility impact that accounts for natural obscuration, CH2M HILL took the measured visual range from the nearest surface station (Sheridan) for hours that included observed weather, and converted the visual range to units of Mm^{-1}. Using the calculated extinction for the obscured hours as a substitute for natural background, the predicted 24-hour visibility impact is reduced to 0.5 percent.

March 9, 2003: Wind Cave NP

The raw, modeled visibility result for this day was 8.0 percent. Transmissometer readings from nearby Badlands NP were missing for all but the final five hours of the day, but surface meteorological observations at Rapid City indicate that strong natural obscuration was in place for most of the day. Observed weather at Rapid City included 11 hours of snow, mist, or haze. Visibility at Rapid City was reduced for each of these 11 hours. To arrive at a predicted visibility impact that accounts for natural obscuration, CH2M HILL took the measured visual range from Rapid City for hours that included observed weather, and converted the visual range to units of Mm^{-1}. Using the calculated extinction for the obscured hours as a substitute for natural background, the predicted 24-hour visibility impact is reduced to 0.7 percent.

December 11, 2003: Wind Cave NP

The raw, modeled visibility result for this day was 7.9 percent. Transmissometer readings at nearby Badlands NP and surface meteorological observations at Rapid City indicate that natural obscuration was in place intermittently during the day. Observed weather at Rapid City included seven hours of light snow. Hourly transmissometer readings at Badlands were greater than 50 Mm^{-1} for the entire day, with four readings of 942 Mm^{-1} (total obscuration). Using the transmissometer reading as a substitute for natural background when the hourly reading exceeded 50 Mm^{-1}, the predicted 24-hour visibility impact is reduced to 0.5 percent.

November 5, 2003: Wind Cave NP

The raw, modeled visibility result for this day was 7.8 percent. Transmissometer readings at nearby Badlands NP and surface meteorological observations in and around Rapid City indicate that natural obscuration was in place. Surface observations at Rapid City include traces of precipitation throughout the day. Measured visibility at Ellsworth AFB is reduced from an instrument maximum reading of 30 miles (48 km) to only 7 miles (11 km) for four hours during the day. The equivalent light extinction value for a visual range of 7 miles is 355 Mm^{-1}. Hourly transmissometer readings at Badlands were greater than 50 Mm^{-1} for the entire day, with a maximum reading of 81 Mm^{-1}. Using the transmissometer reading as a substitute for natural background when the hourly reading exceeded 50 Mm^{-1}, the predicted 24-hour visibility impact is reduced to 2.2 percent.

December 12, 2003: Badlands NP

The raw, modeled visibility result for this day was 5.01 percent. Transmissometer readings from Badlands NP and surface meteorological observations at Rapid City indicate that natural obscuration was in place for most of the day. Observed weather at Rapid City included two hours of mist. Visibility at Rapid City was reduced for several hours, with a minimum reading of 1.2 miles. Hourly transmissometer readings at Badlands were greater than 50 Mm^{-1} for the entire day, with two readings of 942 Mm^{-1} (total obscuration). Using the transmissometer reading as a substitute for natural background when the hourly reading exceeded 50 Mm^{-1}, the predicted 24-hour visibility impact is reduced to 0.4 percent.

November 3, 2003: Northern Cheyenne Indian Reservation

The raw, modeled visibility result for this day was 51.8 percent. Surface meteorological observations at Billings, Montana and Sheridan, Wyoming indicate that a weather event is affecting the area with strong natural obscuration. Observed weather at Billings included 10 hours of snow or mist, and observed weather at Sheridan included 11 hours of mist or freezing rain/rain. Visibility was reduced at Sheridan for the hours that weather was observed, with a minimum reading of 1.5 miles. To arrive at a predicted visibility impact that accounts for natural obscuration, CH2M HILL took the measured visual range from the nearest surface station (Sheridan) for hours that included observed weather, and converted the visual range to units of Mm^{-1}. Using the calculated extinction for the obscured hours as a substitute for natural background, the predicted 24-hour visibility impact is reduced to 2.1 percent.

8.5.3 Criteria Pollutant Impacts

CALPOST was also used to produce estimated concentrations of NO_x, SO_2, and PM_{10} for comparison to the Class I modeling significance levels. Modeled impacts for Dry Fork Station for 2001-2003 were below all Class I modeling significance levels (SIL) for all pollutants at Wind Cave NP and Badlands NP. For Northern Cheyenne, the 3-hour significance level for SO_2 of 1.0 $\mu g/m^3$ was exceeded with 2003 meteorology (1.23 $\mu g/m^3$). The 24-hour significance level of 0.2 $\mu g/m^3$ was also exceeded, with a maximum of 0.55 $\mu g/m^3$ with 2003 meteorology. All other predicted impacts at Northern Cheyenne were below the modeling significance levels. Table 8-5 presents a summary of the predicted criteria pollutant impacts.

TABLE 8-5
Modeled Criteria Pollutant Impacts ($\mu g/m^3$)

Area	Annual NO_2	3-hour SO_2	24-Hour SO_2	Annual SO_2	24-Hour PM_{10}	Annual PM_{10}
2001						
Wind Cave NP	0.003	0.39	0.13	0.009	0.005	0.0003
Badlands NP	0.001	0.33	0.08	0.005	0.002	0.0001
Northern Cheyenne Indian Reservation	0.003	0.68	0.22	0.008	0.01	0.0004
2002						
Wind Cave NP	0.004	0.45	0.17	0.011	0.006	0.0004
Badlands NP	0.002	0.32	0.09	0.007	0.002	0.0001
Northern Cheyenne Indian Reservation	0.002	0.55	0.20	0.006	0.01	0.0003
2003						
Wind Cave NP	0.004	0.49	0.11	0.012	0.005	0.0004
Badlands NP	0.001	0.23	0.07	0.006	0.002	0.0001
Northern Cheyenne Indian Reservation	0.002	1.23	0.55	0.008	0.02	0.0004
Class I Modeling Significance Levels	0.1	1.0	0.2	0.1	0.3	0.2

Notes:

$\mu g/m^3$ = micrograms per cubic meter

Class I Modeling Significance Levels were proposed by EPA on July 23, 1996 [61 FR 38250], but were never adopted as a final rule.

It should be pointed out that the modeling Class I area SIL is intended to be a level above which further analysis of the consumption of the Class I increment is warranted. Typically, the SIL is set at about 5 percent of the overlying increment. In the case of the Class I SIL, EPA proposed them in the Federal Register on July 1996 (Vol. 61, Number 142, Proposed Rules, pg. 38249-344). However, EPA has not acted to make the Class I area SIL a requirement by rule as they have the Class II area SIL. Therefore, the Class I SIL are proposed only. Nevertheless, WDEQ has requested that a Class I cumulative increment consumption analysis be done for SO_2 at the Northern Cheyenne Indian Reservation, and such an analysis was conducted. Cumulative modeling of Class I SO_2 increment consumption at Northern Cheyenne is described in Section 8.6.

8.5.4 Atmospheric Deposition

Impacts to both flora and water quality at the areas of concern were assessed through an analysis of total sulfur (S) and nitrogen (N) deposition. Annual deposition rates were determined for the proposed boiler only.

The NPS has established DAT for eastern and western regions of the United States. A DAT is the amount of deposition within an area below which estimated impacts from a proposed new or modified source are considered insignificant. The DAT for western United States areas is 0.005 kg/ha/yr for total N and also for total S (NPS, 2002).

Annual deposition rates of NO_x, nitric acid (HNO_3), and nitrate (NO_3) were calculated by CALPUFF, converted to equivalent levels of N and summed within the POSTUTIL routine, converted to units of $g/m^2/s$ within CALPOST, and then converted finally to units of kg/ha/yr. Likewise, deposition rates of SO_2 and SO_4 were converted to equivalent levels of N and S and summed. Because DAT levels for deposition established by the NPS are expressed in units of kg/ha/yr for total N or S, the CALPUFF deposition fluxes of each of the species of N and S were adjusted to account for the difference in molecular weights between the species and the chemical elements that comprise them. CH2M HILL used the molecular weight ratios shown in Table 8-6 within the POSTUTIL routine to perform the adjustment.

TABLE 8-6
Molecular Weight Ratios for Deposition Calculations in CALPOST

Element	Ratio of Molecular Weights
N from SO_4	0.29167*
N from HNO_3	0.22222
N from NO_3	0.45161**
N from NO_x	0.30435
S from SO_2	0.50000
S from SO_4	0.33333

*Based on two moles of N in $(NH_4)_2SO_4$

**Based on two moles of N in NH_4NO_3

Table 8-7 presents the estimated deposition of N and S compounds for Dry Fork Station. Appendix H provides the raw g/m^2/s values for each Class I area and each year.

TABLE 8-7
Modeled Atmospheric Deposition

Area	Total N Deposition (kg/ha/yr)	Total S Deposition (kg/ha/yr)
2001		
Wind Cave NP	0.002	0.006
Badlands NP	0.001	0.003
Northern Cheyenne Indian Reservation	0.002	0.006
2002		
Wind Cave NP	0.002	0.006
Badlands NP	0.001	0.002
Northern Cheyenne Indian Reservation	0.001	0.004
2003		
Wind Cave NP	0.002	0.008
Badlands NP	0.001	0.003
Northern Cheyenne Indian Reservation	0.002	0.006
National Park Service Deposition Analysis Threshold	0.005	0.005

8.5.5 Modeled Impacts at Devils Tower

CH2M HILL also modeled criteria pollutant and visibility impacts at Devils Tower National Monument, a Class II area national monument located approximately 65 km northeast of the proposed Dry Fork Station. Table 8-8 presents the results of the criteria pollutant impacts. All modeled impacts were well below the Class II modeling significance levels.

TABLE 8-8
Modeled Criteria Pollutant Impacts (Devils Tower)

Area	Annual NO_2	3-hour SO_2	24-Hour SO_2	Annual SO_2	24-Hour PM_{10}	Annual PM_{10}
2001	0.02	2.0	0.6	0.04	0.06	0.004
2002	0.03	1.9	0.6	0.05	0.06	0.005
2003	0.03	2.1	0.6	0.05	0.06	0.005
Class II Modeling Significance Levels	1	25	5	1	5	1

Raw, modeled visibility results at Devils Tower for 2001-2003 include a single day that exceeded a 5 percent change as compared to natural background. The maximum predicted impact was 5.3 percent. This result occurred on March 22, 2001, which is the same day that yielded 19 hours of fog, mist, or rain in the Rapid City area. An examination of NOAA ~~surface weather maps for this day shows a stationary weather front that is located directly~~ over the Devils Tower area and extending into the Black Hills region of South Dakota. The presence of this weather-producing front indicates that the modeled result at Devils Tower for this day is influenced by natural obscuration.

8.6 Cumulative SO_2 Modeling at the Northern Cheyenne Indian Reservation

8.6.1 Modeling Domain and Technical Approach

To conduct a cumulative increment consumption analysis at the Northern Cheyenne Indian Reservation in southern Montana, CH2M HILL established a CALMET/CALPUFF modeling domain that was centered on the reservation itself. Figure 8-4 shows the modeling domain, which covers a region 600 km by 600 km. This domain is sized to potentially accommodate any source within the accepted effective distance of the CALPUFF model, which is 300 km.

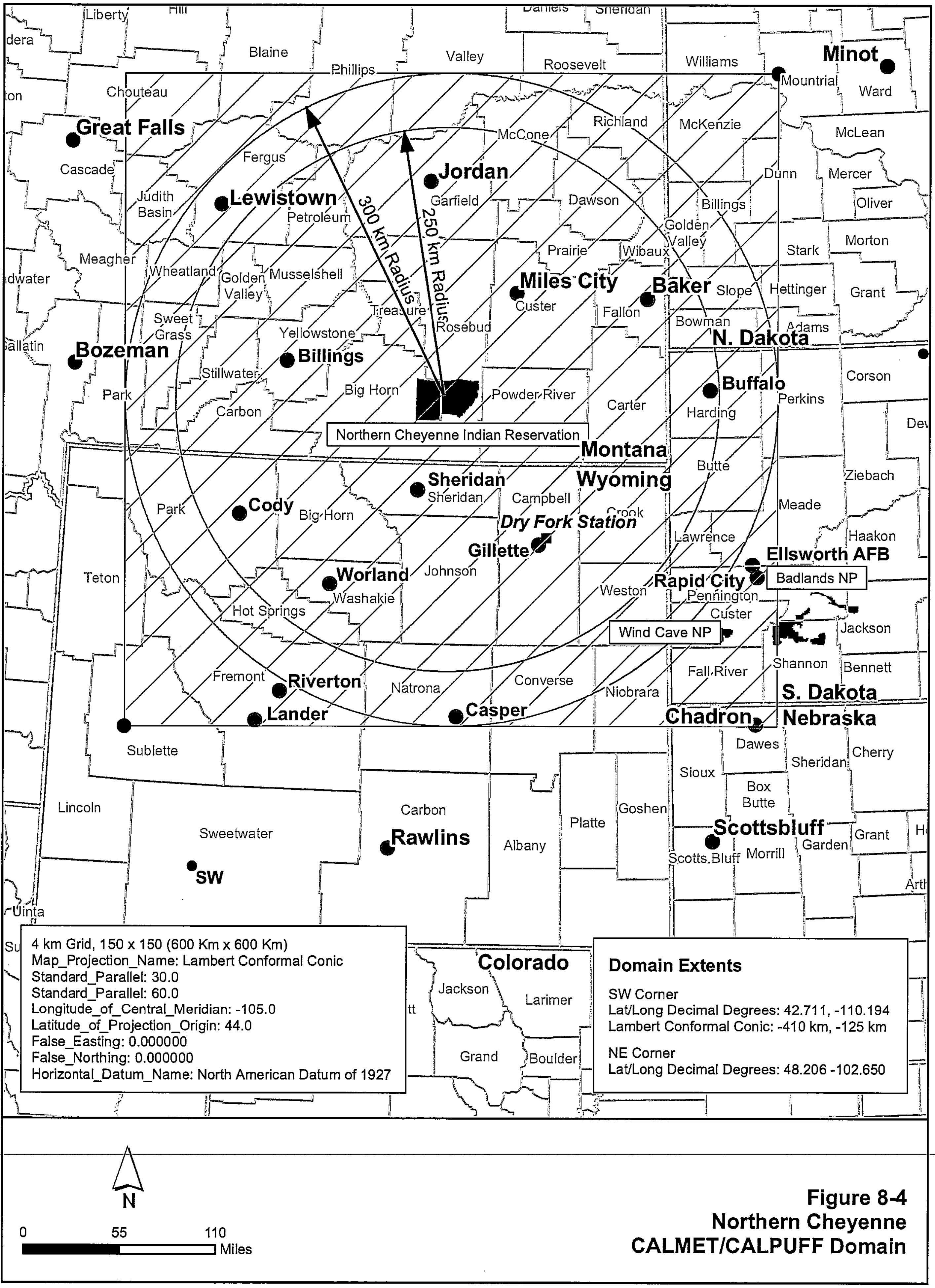
All CALMET and CALPUFF technical options that were employed for the project-only analysis were also employed for the cumulative modeling. These options include the key LCC map projection parameters and the CALMET grid cell resolution of 4 km. Because the cumulative domain is shifted to the north and west of the project-only domain, several new surface and precipitation files were added to the CALMET analysis. Figure 8-4 shows the surface meteorological stations that were used in the cumulative domain. Figure 8-5 shows the locations of precipitation stations that were considered for the analysis. As with the project-only analysis, upper-air observations from Rapid City, South Dakota were input to CALMET to adjust the initial guess wind field, and CH2M HILL ran the CALMET model to produce three years of analysis: 2001, 2002 and 2003.

8.6.2 Validation of CALMET Wind Field

As with the project-only wind fields, CH2M HILL used the CalDESK data display and analysis system (v2.9, Enviromodeling Ltd.) to view plots of wind vectors to evaluate the CALMET wind fields. The same periods chosen for evaluation with the initial wind fields were also evaluated for the cumulative wind fields to judge the accuracy and consistency of CALMET modeling.

8.6.2.1 2001

The first day examined for 2001 was January 3. This day was chosen because the surface weather map showed that high pressure was in place over the modeling domain, and nighttime drainage winds from the higher terrain would be expected. This was reflected in the CalDESK views for the evening hours, which showed pronounced downslope flows from the Black Hills in South Dakota, the Big Horns in Wyoming, and along the west-central edge of the domain in Montana near the Absaroka Range. The 500-millibar map showed that the upper-level, high-pressure area was centered on the west coast at 7:00 A.M. EST, with clockwise flow bringing northwest to southeast wind aloft. This flow was reflected in the highest layer of the wind field during this timeframe.



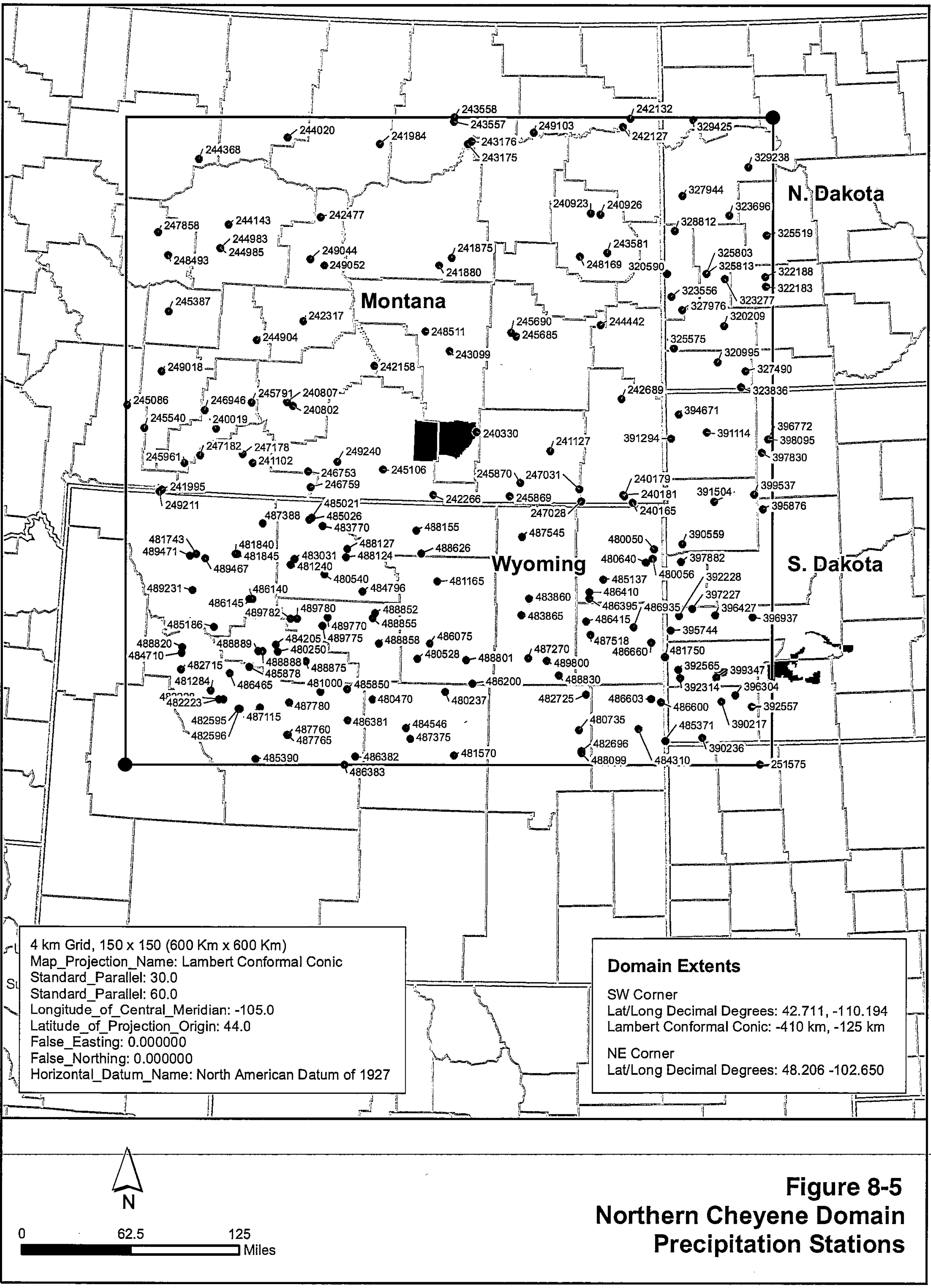
4 km Grid, 150 x 150 (600 Km x 600 Km)
Map_Projection_Name: Lambert Conformal Conic
Standard_Parallel: 30.0
Standard_Parallel: 60.0
Longitude_of_Central_Meridian: -105.0
Latitude_of_Projection_Origin: 44.0
False_Easting: 0.000000
False_Northing: 0.000000
Horizontal_Datum_Name: North American Datum of 1927

Domain Extents

SW Corner
Lat/Long Decimal Degrees: 42.711, -110.194
Lambert Conformal Conic: -410 km, -125 km

NE Corner
Lat/Long Decimal Degrees: 48.206 -102.650

Figure 8-4
Northern Cheyenne
CALMET/CALPUFF Domain



4 km Grid, 150 x 150 (600 Km x 600 Km)
Map_Projection_Name: Lambert Conformal Conic
Standard_Parallel: 30.0
Standard_Parallel: 60.0
Longitude_of_Central_Meridian: -105.0
Latitude_of_Projection_Origin: 44.0
False_Easting: 0.000000
False_Northing: 0.000000
Horizontal_Datum_Name: North American Datum of 1927

Domain Extents

SW Corner
Lat/Long Decimal Degrees: 42.711, -110.194
Lambert Conformal Conic: -410 km, -125 km

NE Corner
Lat/Long Decimal Degrees: 48.206 -102.650

Figure 8-5
Northern Cheyene Domain
Precipitation Stations

July 4 was another day that was dominated by high pressure at the surface, as shown in the NOAA weather maps. Pronounced drainage winds were in evidence on the CalDESK views for the evening hours of July 4, with the flows changing directions with sunrise.

8.6.2.2 2002

December 20, 2002 was a day with high pressure in place at the surface over the modeling domain. As expected, downslope winds were seen in the overnight hours on the CalDESK views, especially from the Big Horns in Wyoming. The upper-level ridge, as seen on the NOAA weather map for the 500-millibar level, was oriented so that winds in the western part of the domain should be west to east and fairly weak, and winds in the eastern part of the domain would be more from the northwest and with higher wind speeds. This was reflected very well in the CalDESK views for the highest layer in the wind field.

CH2M HILL chose September 16 as a warm-weather day that should show strong upslope/ downslope flows due to high pressure at the surface and an overall quiet weather pattern. Nighttime CalDESK views of the wind field showed pronounced downslope winds that diminished with sunrise and through the morning hours.

8.6.2.3 2003

The NOAA surface weather map for January 6 showed a strong surface high pressure area centered near the northwest corner of Wyoming. Nighttime winds during this period, as shown in the CalDESK views, displayed pronounced downslope flows from the Black Hills in South Dakota, the Big Horns in Wyoming, and along the west-central edge of the domain in Montana near the Absaroka Range. This downslope wind pattern would be expected with high pressure dominating at the surface and this pattern was also seen with the 2003 windfield that was centered on the Dry Fork Station. The upper-level ridge on this day was positioned so that winds at the highest level of the domain should be blowing nearly north to south in the central portion of the domain, which is clearly evident on the CalDESK views. The shape of the upper-level isobars on the NOAA map indicate that winds near the southeast corner of the domain would be somewhat lighter, with wind directions with more of a component toward the southeast, and that is also reflected on the CalDESK views.

July 10 was chosen as warm-weather day that should show strong upslope/downslope flows due to high pressure at the surface and an overall quiet weather pattern. Nighttime CalDESK views of the wind field showed pronounced, downslope winds that changed direction with sunrise. Daytime winds showed strong upslope flows, especially near the Big Horns and the Absarokas. The upper-level ridge on this day was positioned to the southwest of the modeling domain in a location that would produce upper-level winds blowing from northwest to southeast. This pattern was shown in the CalDESK views for the highest layer in the wind field, with strong winds blowing from the northwest across the entire domain.

Based on our review of these test days, we conclude that the use of MM5 and other meteorological data processed through CALMET produced wind fields that are expected and reasonable for the modeling domain.

8.6.3 Source and Emissions Inventory

To determine the inventory of sources to include in the cumulative Class I SO_2 increment consumption analysis, CH2M HILL considered the states that fall within a 300-km radius of the Northern Cheyenne Indian Reservation. These states include Montana, Wyoming, the northwest corner of South Dakota, and the extreme southwest corner of North Dakota.

For North Dakota sources, CH2M HILL included the Gascoyne Generating Station, a recently permitted coal-fired power plant in Bowman County in extreme southwest North Dakota. For sources in South Dakota, the South Dakota Department of Environment & Natural Resources was contacted, and an extraction from their emissions database was requested. A review of the data extraction provided by the Department revealed that four very small sources of SO_2 were located with 300 km of the reservation. Due to the large distance of these sources from the reservation and the low magnitude of the emissions, none of the South Dakota sources were input to CALPUFF.

Sources in Montana were provided by the Montana Department of Environmental Quality Air Resources Management Bureau. Locations and stack parameters were provided for the following sources in southern Montana:

- Colstrip Units 3 and 4
- Rocky Mountain Power (Hardin)
- Rocky Mountain Ethanol
- Colstrip Energy Limited Partnership
- Roundup Power Project Units 1 and 2

The SO_2 emission rates provided for these sources were based on permit limits. Because PSD rules dictate that the amount of PSD increment consumption within an area is to be based on actual emission increases and decreases, CH2M HILL attempted to find actual emissions that were representative of the largest source, Colstrip. Actual, hourly emissions for Colstrip Units 3 and 4 for the last two full calendar years, 2003 and 2004, were downloaded from the EPA Clean Air Markets website (http://cfpub.epa.gov/gdm/) and imported to an Excel spreadsheet. Using this spreadsheet, 3-hour and 24-hour block averages of the actual emission rates were calculated for the entire 2-year period. Lastly, the 90th percentile of these block averages were calculated:

- Colstrip Unit 3: 878.5 lb/hr for 3-hour, 835.7 lb/hr for 24-hour
- Colstrip Unit 4: 882.9 lb/hr for 3-hour, 838.1 lb/hr for 24-hour

The approach of using 90th percentile emissions to represent short-term, increment-consuming emissions from a given source has used in practice in other recent analyses, and is a conservative representation of simultaneous operation of the two units at Colstrip. All other Montana sources were conservatively modeled at permitted (allowable) short-term emission rates.

Input data for sources in Wyoming were provided by the WDEQ or assembled at WDEQ's offices. The master list of Wyoming source to possibly include in the analysis included the following:

- Wygen1
- Wygen2
- Neil Simpson Unit 1
- Neil Simpson Unit 2
- Wyodak Unit 1
- 2 Elk Unit 1
- KFX

All of these source were include in the analysis with the exception of Wyodak Unit 1. This source was constructed in 1972, which is prior to the major source baseline date for SO_2. In December of 1986, a scrubber was installed to control SO_2 emissions. With the installation of the scrubber, current short-term SO_2 emissions would be lower than the emissions during the baseline period. Therefore, the source would actually expand increment, but was merely removed from the analysis. All other Wyoming sources were conservatively modeled with their respective allowable short-term emissions for SO_2.

Figure 8-6 shows the locations of all of the sources that were included in the cumulative analysis. Detailed input parameters for each source are presented in Appendix H.

8.6.4 Modeling Results

Results of the modeling show that the cumulative impacts of increment-consuming sources in the area surrounding the Northern Cheyenne Indian Reservation are below the allowable increments. The highest 2nd-high 3-hour impact of 16.7 µg/m^3 was modeled with 2003 meteorology. This modeled impact is well below the Class I PSD increment of 25 µg/m^3. For 24-hour impacts, the highest 2nd-high impact of 4.0 µg/m^3 was modeled with 2002 meteorology. This modeled impact is below the Class I PSD increment of 5 µg/m^3. The results of the cumulative modeling are shown in Table 8-9.

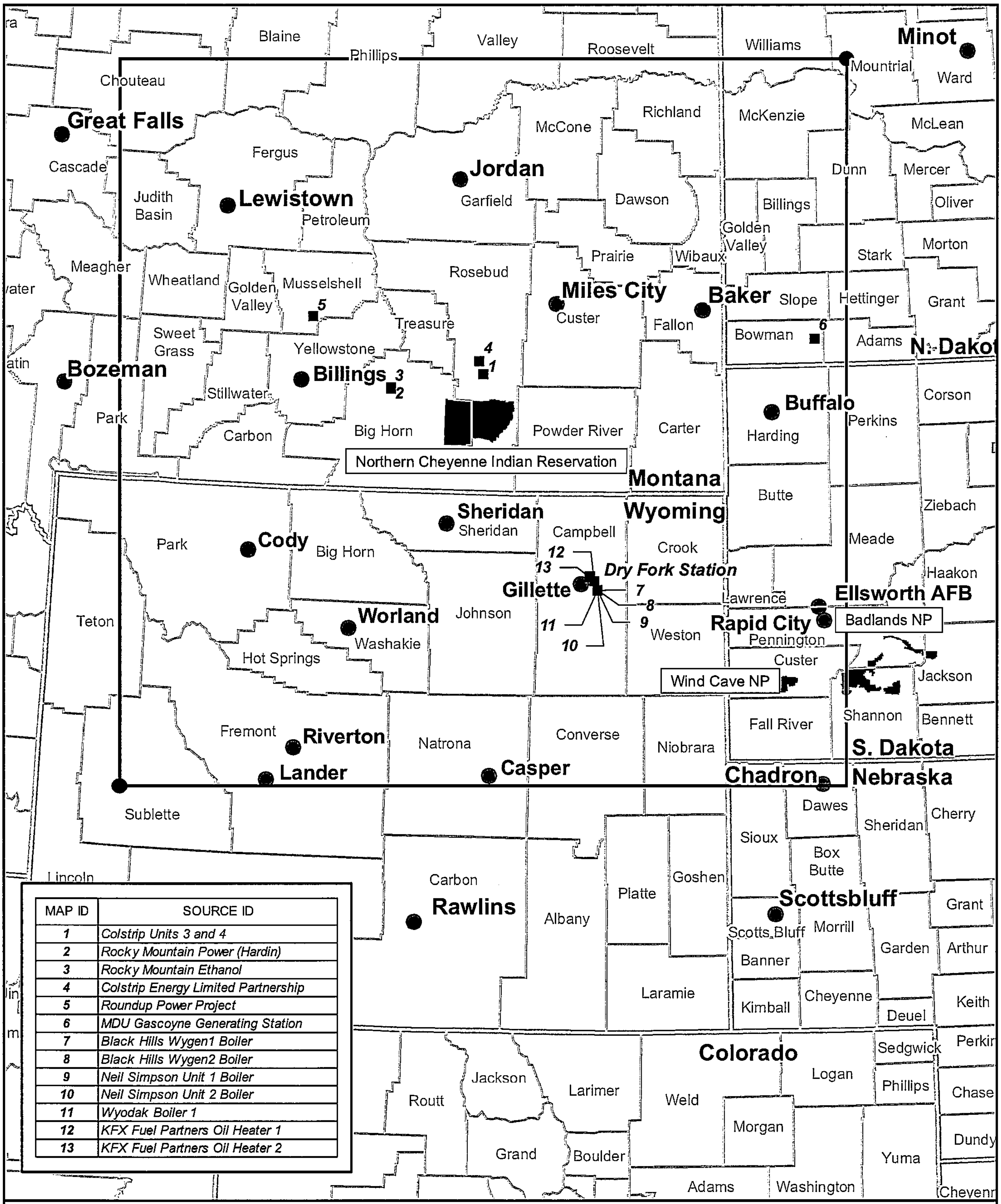
TABLE 8-9
Cumulative Modeled Class I SO_2 Increment Consumption in Northern Cheyenne Indian Reservation (µg/m^3)

Year of Meteorology	Highest 2nd-High 3-hour SO_2	Highest 2nd-High 24-Hour SO_2
2001	15.3	2.9
2002	15.1	4.0
2003	16.7	3.2
Class I PSD Increment	25	5

Notes:
PSD = Prevention of Significant Deterioration

µg/m^3 = micrograms per cubic meter

Class I Modeling Significance Levels were proposed by EPA on July 23, 1996 [61 FR 38250], but were never adopted as a final rule.



MAP ID	SOURCE ID
1	*Colstrip Units 3 and 4*
2	*Rocky Mountain Power (Hardin)*
3	*Rocky Mountain Ethanol*
4	*Colstrip Energy Limited Partnership*
5	*Roundup Power Project*
6	*MDU Gascoyne Generating Station*
7	*Black Hills Wygen1 Boiler*
8	*Black Hills Wygen2 Boiler*
9	*Neil Simpson Unit 1 Boiler*
10	*Neil Simpson Unit 2 Boiler*
11	*Wyodak Boiler 1*
12	*KFX Fuel Partners Oil Heater 1*
13	*KFX Fuel Partners Oil Heater 2*

Figure 8-6
Sources for Northern Cheyenne
Cumulative Modeling

8.7 References

CH2M HILL, 2005. *Protocol for a CALPUFF Modeling Analysis of the Dry Fork Station Project (Northeast Wyoming Generation Project).* August 2005.

EPA, 1998. *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts,* Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, December 1998.

FLAG, 2000. *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report,* December 2000.

NPS, 2002. *Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds,* National Park Service Air Resources Division, Denver, Colorado, January 2002.

WDEQ, 2003. *Wyoming Air Quality Standards & Regulations.* Chapter 6 - Permitting Requirements; Section 4 - Prevention of Significant Deterioration.

Section 9

Monitoring

SECTION 9.0

Monitoring Information

This section describes the compliance monitoring devices and activities that will be employed at the Dry Fork Station. The applicable test methods used for determining compliance are also described.

9.1 Compliance Monitoring Devices and Activities

Unit 1 will be equipped with a CEMS that is compliant with the requirements of 40 CFR Part 75 for the measurement of SO_2 and NO_x and 40 CFR Part 60 for the measurement of CO. Visible emissions (opacity) will be measured with a COMS installed at the outlet of the baghouse. BEPC will install, properly maintain, and operate a continuous mercury emissions monitoring system on Unit 1 as described in 40 CFR Part 60.45a, or a sorbent trap monitoring system as described in 40 CFR Part 72 and 75.

9.2 Applicable Test Methods

Listed below are the EPA test methods from 40 CFR 60, Appendix A, and other test methods that are applicable to this project. These will be used to demonstrate compliance with permit limits.

Method 1 — Sample and Velocity Traverses for Stationary Sources
This method is designed to aid in the representative measurement of pollutant emissions and/or total volumetric flow rate from a stationary source. A measurement site where the effluent stream is flowing in a known direction is selected, and the cross-section of the stack is divided into a number of equal areas. Traverse points are then located within each of these equal areas.

Method 2 — Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)
This method is applicable for the determination of the average velocity and the volumetric flow rate of a gas stream.

Method 3A — Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)
This method is applicable to the determination of O_2 and CO_2 concentrations in emissions from stationary sources only when specified within the regulations.

Method 5 and/ or Method 17 — Determination of Particulate Matter Emissions from Stationary Sources
Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at a temperature of 120 ± 14°C (248 ± 25°F) or such other temperature as specified by an applicable subpart of the standards or approved by the administrator for a ~~particular application. The PM mass, which includes any material that condenses at or~~

above the filtration temperature, is determined gravimetrically after the removal of uncombined water.

Method 6C — Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)

This method is applicable to the determination of SO_2 concentrations in controlled and uncontrolled emissions from stationary sources. A gas sample is extracted continuously from a stack, and a portion of the sample is conveyed to an instrumental analyzer for determination of SO_2 gas concentration using an ultraviolet (UV), nondispersive infrared (NDIR), or fluorescence analyzer.

Method 7E — Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)

This method is applicable to the determination of NO_x concentrations in emissions from stationary sources. A gas sample is extracted continuously from a stack, and a portion of the sample is conveyed to an instrumental chemiluminescent analyzer for determination of NO_x concentration.

Method 8 — Determination of Sulfuric Acid and Sulfur Dioxide Emissions from Stationary Sources

A gas sample is extracted isokinetically from the stack. The H_2SO_4 and the SO_2 are separated, and both fractions are measured separately by the barium-thorin titration method.

Method 9 — Visual Determination of the Opacity of Emissions from Stationary Sources

This method is applicable for the determination of the opacity of emissions from stationary sources pursuant to § 60.11(b) and for qualifying observers for visually determining opacity of emissions. The opacity of emissions from stationary sources is determined visually by a qualified observer.

Method 10 — Determination of Carbon Monoxide Emissions from Stationary Sources

This method is applicable for the determination of CO emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards. The test procedure will indicate whether a continuous or integrated sample is to be used. The integrated or continuous gas sample is extracted from a sampling point and analyzed for CO content using a Luft-type NDIR or equivalent.

Method 19 — Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates

1.0 Emission Rates. O_2 or CO_2 concentrations and appropriate F factors (ratios of combustion gas volumes to heat inputs) are used to calculate pollutant emission rates from pollutant concentrations.

2.0 Sulfur Reduction Efficiency and SO_2 Removal Efficiency. An overall SO_2 emission reduction efficiency is computed from the efficiency of fuel pretreatment systems, where applicable, and the efficiency of SO_2 control devices.

    2.1 The sulfur removal efficiency of a fuel pretreatment system is determined by fuel sampling and analysis of the sulfur and heat contents of the fuel before and after the pretreatment system.

2.2 The SO_2 removal efficiency of a control device is determined by measuring the SO_2 rates before and after the control device.

2.3 The inlet rates to SO_2 control systems (or, when SO_2 control systems are not used, SO_2 emission rates to the atmosphere) are determined by fuel sampling and analysis.

Method 25 — Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
This method is applicable for the determination of volatile organic compounds (VOC) measured as total gaseous nonmethane organics (TGNMO) and reported as carbon in stationary source emissions. Samples are withdrawn from a stack at a constant rate through a heated filter and chilled condensate trap by means of an evacuated sample tank. The sample concentrations are measured by a FID analyzer.

Method 25A — Determination of Total Gaseous Organic Concentration (Flame Ionization Analyzer Method)
This method is used for the measurement of total organic compounds. A gas sample is extracted from a source through a heated sample line and glass fiber filter to a flame ionization analyzer (FIA). Results are reported as volume concentration equivalents of the calibration gas or as carbon equivalents.

Method 26A — Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources (Isokinetic Method)
This method is applicable for determining emissions of hydrogen halides {HCL, HF, and HBr] and halogens [X_2, CL_2 and Br_2] from stationary sources. This method collects the sample isokinetically and collects the sample on a filter and in absorbing solutions and the analysis is performed via ion chromatograph.

Methods 201 and 201A — Determination of Filterable PM_{10} Emissions
Methods 201 and 201A are used to determine filterable PM_{10} emissions from stationary sources. Method 201, known as the Exhaust Gas Recycle Procedure, extracts a gas sample isokinetically from the source. An in-stack cyclone is used to separate PM greater than PM_{10}, and an in-stack glass fiber filter is used to collect PM_{10}. To maintain isokinetic flow rate conditions at the tip of the probe and a constant flow rate through the cyclone, a clean, dried portion of the sample gas at stack temperature is recycled into the nozzle. The particulate mass is determined gravimetrically after removal of uncombined water. An alternate procedure, Method 201A, known as the Constant Sampling Rate Procedure, extracts a gas sample at a constant flow rate through an in-stack sizing device, which separates PM greater than PM_{10}. The particulate mass is determined gravimetrically after removal of uncombined water.

Method 202 — Determination of Condensable Particulate Emissions From Stationary Sources
This method applies to the determination of condensable particulate matter (CPM) emissions from stationary sources. For this project, it will be applicable to the combustion sources only. The method may be used in conjunction with Method 201 or 201A if the probe is glass-lined. The CPM is collected in the impinger portion of a Method 17 type sampling train. The impinger contents are immediately purged after the run with nitrogen to remove dissolved sulfur dioxide gases from the impinger contents. The impinger solution is then extracted with methylene chloride. The organic and aqueous fractions are then taken to

dryness and the residues weighed. The total of both fractions represents the condensable particulate matter.

Recently, an interference problem has been identified with Method 202 as it is presently performed. The present method can capture gaseous SO_2 in the impingement train and include it along with condensed particles in the analysis. EPA is aware of this interference problem and is researching changes to the method, although none have been proposed. Other organizations, most notably EPRI, have proposed a similar condensable particulate test method which does not have this interference problem. Accordingly, BEPC requests that the condensable particulate fraction be determined by Method 202, if at the time Unit 1 starts up the method has been changed by EPA to eliminate this problem, or by an alternate test method acceptable to the WDEQ.

Ontario Hydro Method — Determination of Mercury Emissions From Stationary Sources

This method applies to the determination of elemental, oxidized, particle-bound, and total mercury emissions from coal-fired stationary sources. A sample is withdrawn from the flue gas stream isokinetically through a probe/filter system, maintained at 120° C or the flue gas temperature, whichever is greater, followed by a series of impingers in an ice bath. Particle-bound mercury is collected in the front half of the sampling train. Oxidized mercury is collected in impingers containing a chilled aqueous potassium chloride solution. Elemental mercury is collected in subsequent impingers (one impinger containing a chilled aqueous acidic solution of hydrogen peroxide and three impingers containing chilled aqueous acidic solutions of potassium permanganate). Samples are recovered, digested, and then analyzed for mercury using cold-vapor atomic absorption (CVAAS) or fluorescence spectroscopy (CVAFS).

Section 10

Compliance

SECTION 10.0

Compliance Plan and Certification

10.1 Evidence of Compliance with Standards

This application is for a PSD Construction permit only and the Title V operating permit application will be filed later, 12 months after startup of Unit 1. Therefore, this section is not yet required. Accordingly, BEPC is providing this section for information purposes only to demonstrate that the construction and operation of the Dry Fork Station will be wholly protective of the environment.

10.2 Compliance Status

BEPC's Dry Fork Station project will be in compliance with applicable environmental laws and regulations. There are no enforcement actions or compliance plans in progress for BEPC.

10.3 Compliance Plan

BEPC's Dry Fork Station will be in compliance with applicable requirements; therefore, no compliance plan is required.

10.3.1 Compliance Schedule

BEPC's Dry Fork Station project will be in compliance with applicable requirements; therefore, there is no compliance schedule is provided.

10.3.2 Other Requirements

BEPC's Dry Fork Station project will meet other applicable requirements that become effective during the term of the permit as required by the WDEQ.

10.4 Compliance Certification

A compliance certification signed by a responsible official of BEPC's Dry Fork Station project will be provided as a part of the Title V permit application filed within 12 months after startup of Unit 1.

10.5 Acid Rain Compliance Plan

BEPC's Dry Fork Station will be in compliance with Title IV Acid Rain Program requirements. An application and compliance plan (as required) for the Dry Fork Station project acid rain permit will be submitted to WDEQ no later than 24 months before the date on which the unit is to commence operation.