Appendix A:
PSD Air Quality Construction Permit Application

This page intentionally left blank.

Basin Electric Power Cooperative
Deer Creek Station
PSD Air Quality Construction Permit Application

Prepared for:

Basin Electric Power Cooperative
Bismarck, North Dakota

Prepared by:

Sargent & Lundy, LLC
Chicago, Illinois

May 29, 2009

BASIN ELECTRIC POWER COOPERATIVE

TABLE OF CONTENTS

1.0 INTRODUCTION

2.0 PROJECT DESCRIPTION

2.1 Site Location
2.1.1 Site Setting
2.1.2 Local Air Quality Attainment/Non-attainment Status
2.1.3 Proximity to Class I Areas
2.2 Facility Equipment
2.2.1 Combustion Turbine / HRSG / Steam Turbine
2.2.2 Air Cooled Condenser
2.2.3 Emergency Generator and Fire Water Pump
2.2.4 Emergency Inlet Air Heater
2.3 Emission Sources
2.4 General Applicant Information
2.5 Standard Industrial Classification (SIC)

3.0 PROJECT EMISSIONS

3.1 Combustion Turbine / HRSG Emissions
3.1.1 CT/HRSG Emissions During Normal Operations
3.1.2 Combustion Turbine Startup Emissions
3.1.3 Annual CT/HRSG Emissions
3.2 Emergency Generator and Diesel Fire Water Pump Emissions
3.3 Emergency Inlet Air Heater Emissions
3.4 Potential Annual Emissions
3.5 Potential Emissions of Non-PSD Pollutants
3.6 Insignificant Activities

4.0 REGULATORY REVIEW

4.0 Introduction
4.1 Overview of Air Quality Regulations
4.2 South Dakota Air Emission Standards
4.2.1 Chapter 74:36:01 - Definitions
4.2.2 Chapter 74:36:02 – Ambient Air Quality
4.2.3 Chapter 74:36:03 – Air Quality Episodes
4.2.4 Chapter 74:36:04 – Operating Permits for Minor Sources
4.2.5 Chapter 74:36:05 – Operating Permits for Part 70 Sources
4.2.6 Chapter 74:36:06 – Regulated Air Pollutant Emissions
4.2.6.1 Subchapter 74:36:06:02 - Allowable Emissions for Fuel-Burning Units
4.2.7 Chapter 74:36:07 – New Source Performance Standards
4.2.8 Chapter 74:36:08 – National Emissions Standards for Hazardous Air Pollutants
4.2.9 Chapter 74:36:00 – Prevention of Significant Deterioration
4.2.10 Chapter 74:36:10 – New Source Review

TABLE OF CONTENTS

4.2.11 Chapter 74:36:11 – Performance Testing
4.2.12 Chapter 74:36:12 – Control of Visible Emissions
4.2.13 Chapter 74:36:13 – Continuous Emission Monitoring Systems
4.2.14 Chapter 74:36:14 – Variances (Repealed, 23 SDR 106)
4.2.15 Chapter 74:36:15 – Open Burning
4.2.16 Chapter 74:36:16 – Acid Rain Program
4.2.17 Chapter 74:36:17 – Rapid City Street Sanding and Deicing
4.2.18 Chapter 74:36:18 – Regulations for State Facilities in the Rapid City Area
4.2.19 Chapter 74:36:19 – Mercury Budget Trading Program
4.3 New Source Performance Standards (NSPS)
4.3.1 40 CFR Part 60 Subpart A: General Provisions
4.3.2 40 CFR Part 60 Subpart KKKK: Combustion Turbines
4.3.3 40 CFR Part 60 Subpart IIII: Stationary Compression Ignition Internal Combustion Engines
4.4 National Emission Standards for Hazardous Air Pollutants (NESHAPS)
4.5 Acid Rain Program
4.6 Compliance Assurance Monitoring

5.0 BEST AVALIABLE CONTROL TECHNOLOGY (BACT) ASSESSMENT

5.0 Introduction
5.1 Definition of BACT
5.2 Summary of Combustion Turbine/HRSG BACT Analysis
5.3 Summary of the Emergency Generator and Fire Water Pump BACT Analysis

6.0 MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (MACT) REQUIREMENTS

6.0 Introduction
6.1 Applicable MACT Standards

7.0 CLASS II AIR QUALITY IMPACT ANALYSIS - SUMMARY

8.0 ADDITIONAL IMPACT ANALYSIS

8.1 Class II Visibility Analysis
8.1.1 Class II Visibility Analysis Results
8.1.2 VISCREEN Input and Output Files
8.2 Growth Analysis
8.3 Soils & Vegetation Analysis

9.0 Proposed Emission Limits

9.1 Proposed Emission Limits – CT/HRSG
9.2 Proposed Emission Limits – Diesel-Fired Stationary Engines and Inlet Air Heater

TABLE OF CONTENTS

APPENDICES:

Appendix A SD Application Forms

Appendix B Supporting Calculations for Emission Estimates

Appendix C Combustion Turbine/HRSG BACT Analysis

Appendix D Class II Impact Modeling Results and Support Documentation

BASIN ELECTRIC POWER COOPERATIVE

LIST OF TABLES

TABLES

Table	Description
2-1	Deer Creek CT/HRSG Operating Parameters – Base Load No Duct Firing
2-2	Deer Creek CT/HRSG Operating Parameters – Base Load With Duct Firing
2-3	Deer Creek CT/HRSG Operating Parameters – Annual Average Ambient Conditions Part Load Cases
2-4	Deer Creek CT/HRSG Operating Parameters – Summer Average Maximum Ambient Conditions Part Load Cases
2-5	Deer Creek Station Emission Point Designations
3-1	CT/HRSG Emissions – Base Load Without Supplemental Duct Firing
3-2	CT/HRSG Emissions – Base Load With Supplemental Duct Firing
3-3	CT/HRSG Maximum Hourly Emissions
3-4	CT/HRSG Startup Emissions – Cold Startup
3-5	CT/HRSG Startup Emissions – Warm Startup
3-6	CT/HRSG Startup Emissions – Hot Restart
3-7	CT/HRSG Estimated Startup Hours per Year
3-8	CT/HRSG Estimated Startup Emissions – NOx
3-9	CT/HRSG Estimated Startup Emissions – CO
3-10	CT/HRSG Estimated Startup Emissions – VOC
3-11	CT/HRSG Annual Emissions Summary
3-12	Emergency Diesel Generator Emissions
3-13	Fire Water Pump Emissions
3-14	Emergency Inlet Air Heater Emissions
3-15	Annual Potential-to-Emit (PTE) Summary
3-16	CT/HRSG – Potential HAP Emissions
3-17	Auxiliary Combustion Sources – HAP Emission Summary
3-18	Deer Creek Potential Annual HAP Emissions
4-1	National Ambient Air Quality Standards
4-2	Allowable PSD Increments and Significant Impact Levels
4-3	Summary of Applicable South Dakota Particulate Emission Limitations
4-4	Comparison of PSD Significant Levels and Expected Annual Emissions

LIST OF TABLES

4-5	40 CFR Part 60 Subpart KKKK New Source Performance Standards
4-6	CI ICE NSPS – Emergency Diesel Generator
4-7	CI ICE NSPS – Fire Water Pump Engines
5-1	Proposed CT/HRSG BACT Emission Limits and Control Technologies
5-2	Proposed Emergency Inlet Air Heater BACT Limits
8-1	VISCREEN Input Emission Rates
8-2	VISCREEN Source-Receptor Distances
8-3	VISCREEN Results for Pipestone National Monument
8-4	VISCREEN Results for Lake Cochrane
8-5	VISCREEN Results for Lake Poinsett
8-6	VISCREEN Results for Oakwood Lakes
8-7	VISCREEN Input and Output Files
8-8	Ambient Air Quality Screening Concentrations for Soils and Vegetation
9-1	Proposed CT/HRSG NOx Emission Limits
9-2	Proposed CT/HRSG CO Emission Limits
9-3	Proposed CT/HRSG PM Emission Limits

LIST OF FIGURES

FIGURES

Figure	Description
2-1	Deer Creek Station – General Location
2-2	Deer Creek Station – Proposed Location and Surrounding Area
2-3	Deer Creek Station – Topographic Map of Surrounding Area
2-4	Deer Creek Station – Site General Arrangement
2-5	Deer Creek Station – Site General Arrangement Elevation View
4-1	Counties Designated Nonattainment for the SO2 NAAQS
4-2	Counties Designated Nonattainment for the 8-hour Ozone NAAQS
4-3	Counties Designated Nonattainment for the PM2.5 NAAQS
8-1	Project Site, State Parks, and the Pipestone National Monument

ACRONYMS AND ABBREVIATION

Acronyms and Abbreviations

AERMOD	AMS/EPA Regulatory Model
AP-42	EPA Compilation of Air Pollution Emission Factors
AQRV	Air Quality-Related Values
BACT	Best Available Control Technology
BEPC	Basin Electric Power Cooperative
Btu/hr	British thermal unit per hour
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
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DENR	South Dakota Department of Environmental and Natural Resources
°F	degrees Fahrenheit
FGR	Flue Gas Recirculation
g/s	Grams per Second
GEP	Good Engineering Practices
gr/dscf	Grains per Dry Standard Cubic Foot
HAP	Hazardous Air Pollutant
hp	Horsepower
hr	Hour
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
LNB	Low NO_x Burner
m	Meter
m/s	Meters per Second
MACT	Maximum Achievable Control Technology
$\mu g/m^3$	Micrograms per Cubic Meter
mmBtu/hr	million British thermal units per hour
MW	Megawatt
MWh	Megawatt Hour

ACRONYMS AND ABBREVIATION

NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia gas
NOx	Nitrogen Oxide
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	Oxygen
PAH	Polyaromatic Hydrocarbons
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 micrometers in diameter
$PM_{2.5}$	Particulate Matter less than 2.5 micrometers in diameter
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
psia	per square inch absolute
psig	per square inch gauge
PTE	Potential to Emit
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SIL	Modeling Significance Impact Level
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
tph	Tons per Hour
tpy	Ton per Year
U.S.EPA	United States Environmental Protection Agency
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

BASIN ELECTRIC POWER COOPERATIVE

1. INTRODUCTION

1.0 INTRODUCTION

Basin Electric Power Cooperative (BEPC) proposes to construct a new natural gas-fired combined cycle power generating facility. The new facility, to be known as the Deer Creek Station, will be located approximately six miles southeast of White, South Dakota, in Brookings County. Upon completion the Deer Creek Station will include:

- one F-class (or the equivalent) combustion turbine (CT) generator;
- one natural circulation, duct fired, heat recovery steam generator (HRSG);
- one steam turbine generator (STG);
- one diesel-fired emergency generator;
- one diesel-fired fire water pump;
- one natural gas-fired emergency inlet air heater; and
- one air cooled condenser (ACC).

The proposed electric generating facility has the potential to emit regulated pollutants in amounts above the significance levels defined in 40 CFR 52.21(b)(23) and South Dakota Air Pollution Control Program Chapter 74:36:09. Therefore, BEPC is applying to the South Dakota Department of Environmental and Natural Resources (DENR) for a Prevention of Significant Deterioration (PSD) Air Quality Construction Permit. PSD review includes:

- determination of Best Available Control Technology (BACT);
- analysis of compliance with National Ambient Air Quality Standards (NAAQS); and
- evaluation of source-related impacts on growth, soils, vegetation, and visibility.

This permit application includes information required to approve the construction of a new major source located in an area meeting all National Ambient Air Quality Standards. Information is presented in the following sections and appendices:

Section 2 - Project Description contains information describing the proposed facility and equipment; the site location and geographic setting; the project proponent (including contact persons for this permit application); and the Standard Industrial Classification Code applicable to the proposed facility.

Section 3 - Project Emissions provides a description of the emission sources and potential emissions from the proposed facility.

1. INTRODUCTION

Section 4 - Regulatory Applicability and Compliance Evaluation provides an assessment of the applicable state and federal air quality regulations.

Section 5 - Best Available Control Technology (BACT) provides a summary of the emission control technologies and emission rates proposed as BACT. The complete BACT Analysis is included in Appendix C.

Section 6 – Maximum Achievable Control Technology provides a summary of the applicable MACT standards.

Section 7 – Class II Ambient Air Quality Impact Analysis presents a summary of the ambient air quality impact modeling conducted to evaluate potential impacts to ambient air quality, PSD increments, and air quality related values. A detailed impact modeling report in included in Appendix C.

Section 8 – Other Impact Analysis presents the results of reviews conducted to assess potential source-related impacts on growth, soils, vegetation, and visibility.

Section 9 – Permit Limits provides a summary of the proposed emission limits.

Appendix A contains the required DENR permit application forms.

Appendix B contains the operating parameters, emission calculations and supporting documentation.

Appendix C is the complete BACT Analysis for the proposed project.

Appendix D is the complete Class II air quality impact assessment for the proposed project.

This permit application includes information and analysis demonstrating that the proposed project will meet the following criteria:

- The proposed facility will comply with all the applicable South Dakota air quality regulations.
- Emissions from the proposed facility will be controlled using technology representing BACT.
- Emission units will meet all applicable new source performance standards.
- Emissions from the proposed facility will not cause significant deterioration of existing ambient air quality in the region and will not exceed allowable PSD increments.

2. PROJECT DESCRIPTION

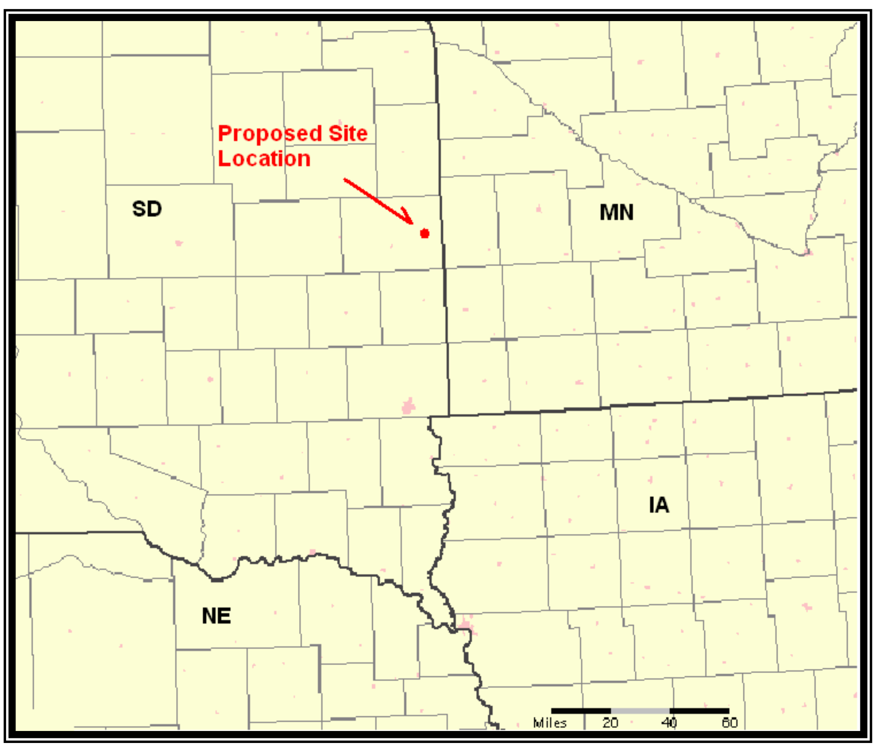
2.0 PROJECT DESCRIPTION

This section contains information on the proposed facility and equipment; the site location and geographic setting; the project proponent (including contact persons for this permit application); and the Standard Industrial Classification Code applicable to the proposed facility.

2.1 Site Location

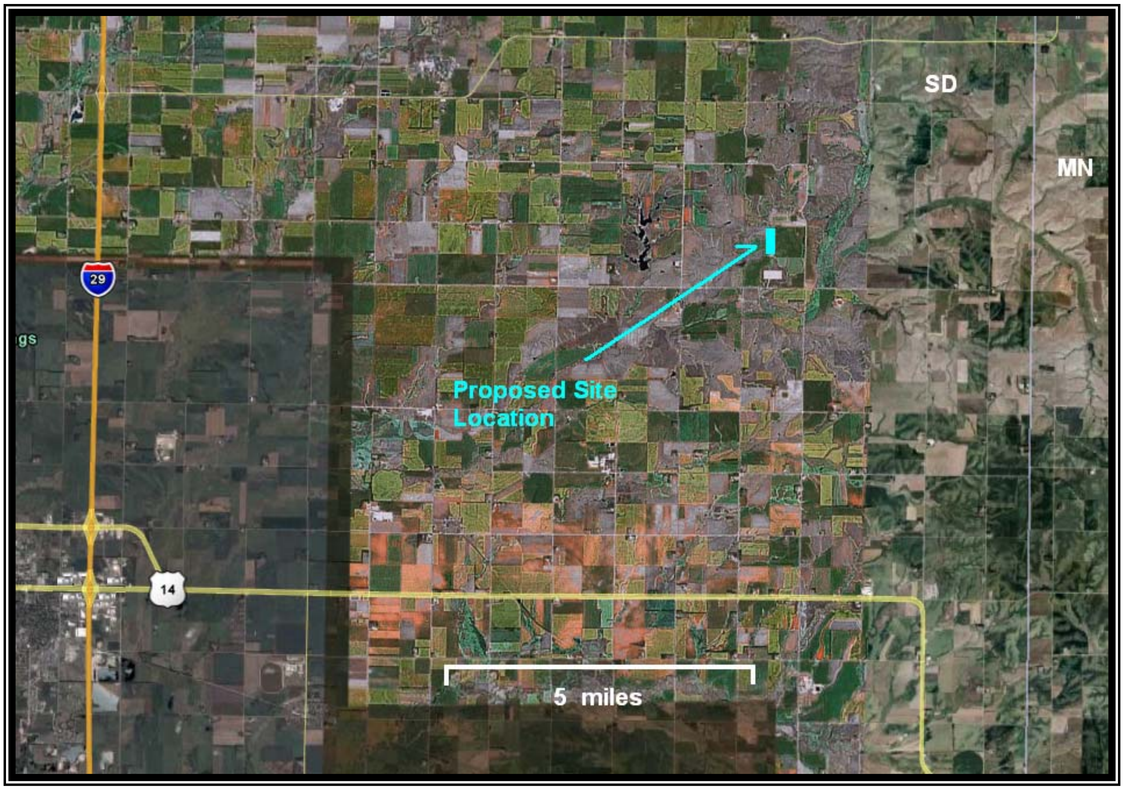
The proposed Deer Creek Station will be located in Brookings County, South Dakota, approximately 12 miles northeast of the town of Brookings near White, South Dakota. Brookings County is located in east-central South Dakota near the Minnesota border. The proposed facility location will be built on about 100 acres of land approximately 5 miles from the existing White substation. The site is accessible via U.S. Highway 177. Figure 2-1 shows the general location of the proposed facility. An aerial photograph of the site and the surrounding area showing the general location of the proposed facility is included as Figure 2-2.

Figure 2-1
Deer Creek Station – General Location



2. PROJECT DESCRIPTION

Figure 2-2
Deer Creek Station – Proposed Location and Surrounding Area



2.1.1 Site Setting

Brookings County South Dakota is characterized by nearly level to gently rolling plains. Brookings County is entirely on the Coteau des Prairies, a high land plateau that extends across the county in a southeasterly direction.[1] The county is divided into four geographic parts, with the flood plain and outwash plain along the Big Sioux River separating the western one-third of the county from the eastern two-thirds. The proposed Deer Creek Station is located east of the Big Sioux River. The area east of the Big Sioux River is characterized by a till plain consisting of loamy glacial till. The till plain is nearly level to gently rolling with well defined drainage patterns.

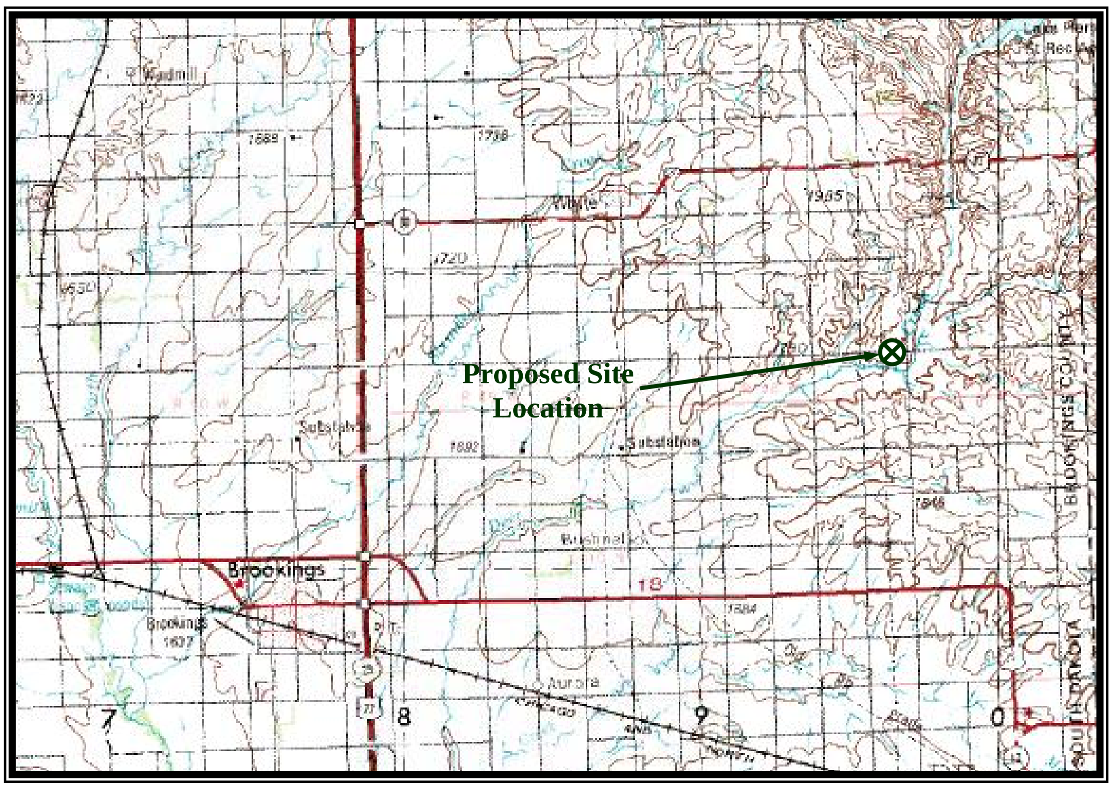
[1] The site setting description provided in this permit application was taken primarily from "Soil Survey of Brookings County, South Dakota," U.S. Department of Agriculture, Natural Resources Conservation Services.

2. PROJECT DESCRIPTION

The climate in the area is characterized by pronounced daily and seasonal changes in temperature and variations in seasonal and annual rainfall. In winter, the average temperature is 14 ^{o}F and the average daily minimum temperature is 3 ^{o}F. In summer, the average temperature is 68 ^{o}F. Total annual precipitation is approximately 23 inches, with about 78% of the total precipitation falling in April through September. Prevailing winds in the area are from the south. Average wind speed is highest in May, averaging approximately 12 miles per hour.

Figure 2-3 is a topographical map of the area near the Deer Creek Station.

Figure 2-3
Deer Creek Station – Topographic Map of Surrounding Area



2. PROJECT DESCRIPTION

2.1.2 Local Air Quality Attainment/Non-attainment Status

Brookings County, and all counties surrounding the proposed site have been designated as attainment areas (or unclassifiable) for all existing national ambient air quality standards (NAAQS), including the 8-hour ozone and fine particulate matter ($PM_{2.5}$) NAAQS.

2.1.3 Proximity to Class I Areas

Certain national parks, wilderness areas, and national wildlife refuges are designated Federal Class I Areas. In general, allowable ambient air quality impacts within Class I Areas are more restrictive than allowable impacts within Class II areas (i.e., attainment areas). If a proposed new major source of emissions is located within approximately 300 km of a Class I Area, the applicant is required to demonstrate, through air quality modeling, that emissions from the proposed project will not cause or contribute to any violations of allowable increments within the affected Class I Area. Applicants are also required to evaluate potential impacts to air quality related values within the Class I Area, including visibility.

The nearest Class I Area to the proposed Deer Creek Station is the Badlands National Park located approximately 420 km (260 miles) west-southwest of the facility. All other Class I Areas are located more than 450 km from the facility.

2.2 Facility Equipment

The proposed Deer Creek Station will be a natural gas-fired combined cycle electric generating facility. Major components of the proposed facility include the combustion turbine, HRSG, and steam turbine generator. Other potential emissions sources at the facility include a diesel-fired emergency generator, diesel-fired fire-water pump, and a natural gas-fired emergency inlet air heater. The general facility layout, including the location of major pieces of equipment and the location of all proposed emission sources, is shown in Figure 2-4. Figure 2-5 shows an elevation view of the combustion turbine and HRSG.

Figure 2-4 - Deer Creek Station – Site General Arrangement

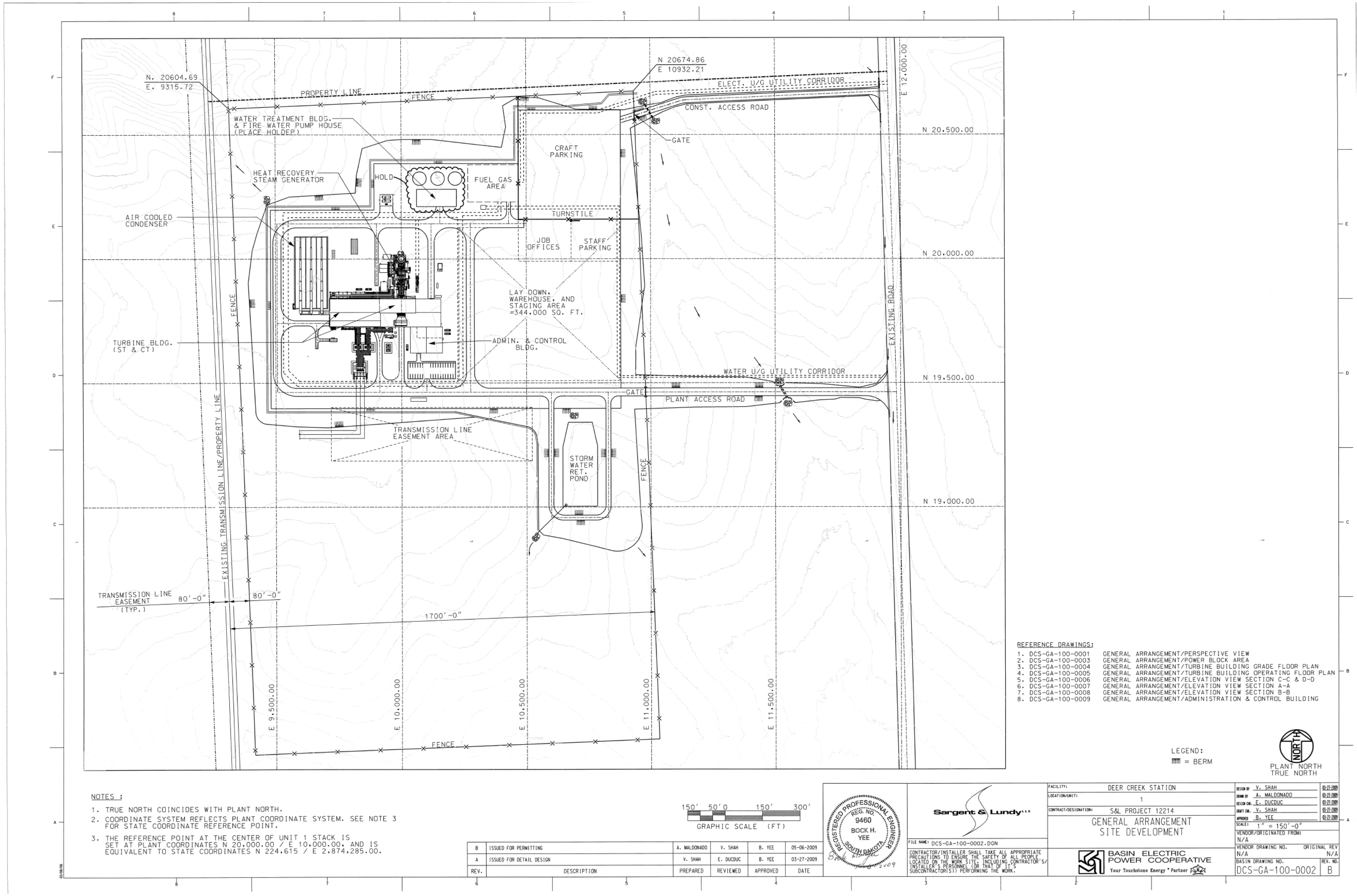
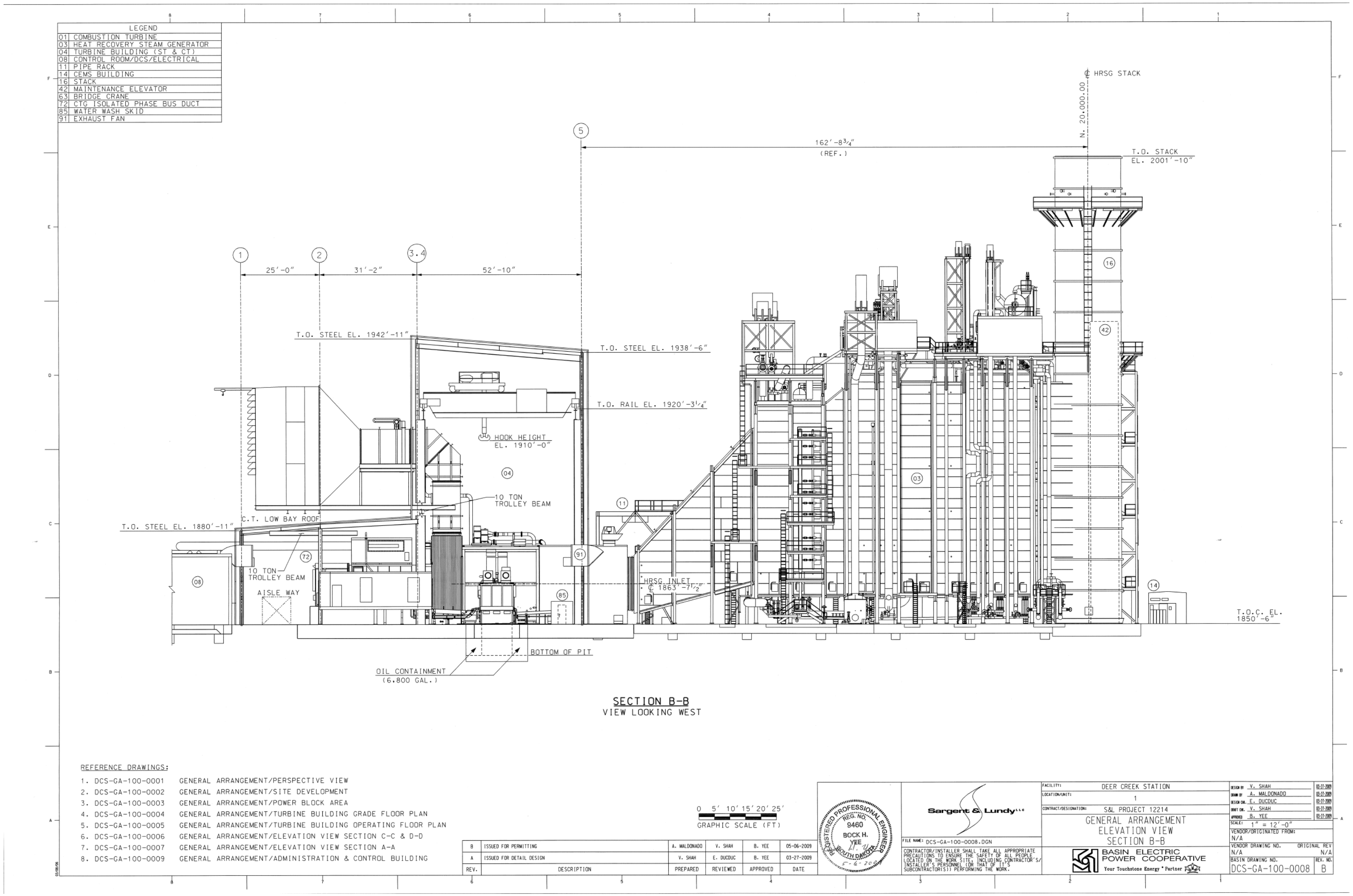


Figure 2-5 - Deer Creek Station – Site General Arrangement Elevation View



2. PROJECT DESCRIPTION

2.2.1 Combustion Turbine/HRSG

The Deer Creek project includes one F-class (or the equivalent) natural gas-fired combustion turbine (CT) and heat recovery steam generator (HRSG). The proposed CT includes an air compressor section, advanced natural gas combustion section, power turbine, and an electrical generator. Ambient air is drawn through an inlet air filter on the CT and compressed in a multiple-stage axial flow compressor. Compressed air and natural-gas are mixed and combusted in the CT combustion chamber. Based on the BACT analysis (Appendix C), dry low-NOx combustors will be used to minimize NOx formation during combustion. Exhaust gas from the combustion chamber is expanded through a multi-stage power turbine, which drives both the air compressor and an electric power generator.

Hot exhaust gas from the CT is directed through the HRSG where excess heat is used to generate steam. The HRSG will be equipped with natural gas-fired duct burners. The duct burners are used to generate additional steam during periods of peak electrical demand. Steam from the HRSG is used to drive a single steam turbine connected to an electrical generator. Exhaust gas from the HRSG passes through additional emission control equipment prior to being discharged to the atmosphere through a single stack.

The CT is designed to produce a nominal 166 MW of gross electrical power at full load and an average annual ambient temperature of 43 °F. CT power output will decrease somewhat as the ambient air temperature increases, and output will increase as ambient temperatures decrease. This change in power output is related to the mass flow of combustion air through the turbine. CT power output at full load with be in the range of 150 MW at a summer ambient temperature of 93 °F, and increase to approximately 180 MW at a winter extreme ambient temperature of -41 °F.

The HRSG used for the Deer Creek Station will be equipped with natural gas-fired duct burners. Heat input to the duct burners will depend on steam requirements and ambient conditions. Based on heat balance performance calculations, heat input to the duct burners will be has high as 610 mmBtu/hr (LHV) during summer ambient conditions. Based on heat balances prepared for the project, steam production at average annual ambient conditions from the HRSG is estimated to be approximately 419,500 lb/hr without duct firing and 792,700 lb/hr without duct firing. Steam from the HRSG will drive a single steam turbine-generator with a nominal power output of 143 MW with duct firing and 84 MW without duct firing at the average annual ambient temperature of 43 °F. Steam turbine exhaust will be directed to an air cooled condenser, and the condensate will be re-used.

2. PROJECT DESCRIPTION

Tables 2-1 and 2-2 provide operating parameters for the CT/HRSG at base load and three ambient air temperatures (93 °F, 43 °F, and -42 °F), with and without supplemental duct firing. Tables 2-3 and 2-4 provide operating parameters for the CT/HRSG at annual average and summer ambient conditions at 75%, 50%, and 25% load. These operating cases cover the expected range of operating conditions for the Deer Creek CT/HRSG, and bracket the expected worst-case emission cases.

Emissions from the CT/HRSG will be controlled using BACT. The complete BACT analysis for Deer Creek is included in Appendix C of this permit application. Based on the BACT analysis, emissions from the CT/HRSG will be controlled by exclusively firing natural gas and using combustion controls (including dry low-NOx burners) and selective catalytic reduction (SCR). The exhaust gas will be ducted through a 150-foot stack.

2.2.2 Air Cooled Condenser

Steam from the low pressure (LP) section of the steam turbine will be condensed in an air cooled condenser (ACC) prior to being recycled. In an air cooled condenser, steam discharged from the turbine enters a steam distribution manifold located at the top of the ACC and is distributed to a number of finned-tube heat exchangers. The steam flows downward through the heat exchanger tubes and is condensed. Mechanical fans are used to force ambient air over the heat exchangers to cool the steam. The condensate is collected in a series of pipes located at the base of the heat exchangers and returned to the steam turbine water system.

There are both advantages and disadvantages to using an air cooled condensing system. The primary disadvantage is related to the auxiliary power requirement associated with the fans used to move ambient air past the heat exchangers. Advantages include a significant reduction in water use (compared to wet cooling systems) and elimination of particulate matter emissions. Because ambient air is used as the cooling medium, and the air cools the steam without coming into contact with the condensate or any other potential contaminants, there are no emissions associated with an air cooled condensing system. Therefore, the ACC has not been identified as an emissions source at the Deer Creek Station.

BASIN ELECTRIC POWER COOPERATIVE

2. PROJECT DESCRIPTION

Table 2-1
Deer Creek CT/HRSG Operating Parameters
Base Load – No Duct Firing

Case		**Case 1**	**Case 3**	**Case 5**
Ambient Conditions		Winter Extreme Case	Annual Average	Summer
Ambient Temperature		-41 oF	43 oF	94 oF
Combustion Turbine Load		Base Load	Base Load	Base Load
Duct Firing (Fired / Unfired)		Unfired	Unfired	Unfired
CT Power Output (per CT)	kW	184,557	166,178	150,600
CT Heat Consumption (per CT LHV)	mmBtu/hr	1,713.0	1,541.0	1,434.0
DB Heat Consumption (per HRSG LHV)	mmBtu/hr	0.0	0.0	0.0
Total Heat Input to CTs + HRSGs	mmBtu/hr	**1,713.0**	**1,541.0**	**1,434.0**
Gross Steam Turbine Output	kW	85,326	83,505	79,936
Total Gross Electrical Output	kW	**269,883**	**249,683**	**230,536**
Auxiliary Power	kW	**5,390**	**6,507**	**10,001**
Net Plant Electrical Output	kw	**264,493**	**243,176**	**220,535**
Net Plant Electrical Heat Rate, LHV	Btu/kWh_{net} (LHV)	**6,477**	**6,337**	**6,502**
Stack Diameter	ft	19.0	19.0	19.0
Flow (total)	lb/hr	3,898,140	3,489,126	3,231,119
Velocity	ft/sec	69.0	61.9	57.8
Temperature	^{o}F	200	200	200
Flow (total)	acfm	1,173,115	1,052,484	982,517
Flow (total)	scfm	878,480	788,146	735,752
Flow (total)	dscfm	814,087	725,567	662,177

2. PROJECT DESCRIPTION

Table 2-2
Deer Creek CT/HRSG Operating Parameters
Base Load – With Duct Firing

Case		**Case 2**	**Case 4**	**Case 6**
Ambient Conditions		Winter Extreme Case	Annual Average	Summer
Ambient Temperature		-41 oF	43 oF	94 oF
Combustion Turbine Load		Base Load	Base Load	Base Load
Duct Firing (Fired / Unfired)		Duct Firing	Duct Firing	Duct Firing
CT Power Output (per CT)	kW	184,557	166,178	150,600
CT Heat Consumption (per CT LHV)	mmBtu/hr	1,713.0	1,541.0	1,434.0
DB Heat Consumption (per HRSG LHV)	mmBtu/hr	297.9	511.1	610.4
Total Heat Input to CTs + HRSGs	mmBtu/hr	**2,010.9**	**2,052.1**	**2,044.4**
Gross Steam Turbine Output	kW	122,116	142,723	152,860
Total Gross Electrical Output	kW	**306,673**	**308,901**	**303,460**
Auxiliary Power	kW	**6,393**	**8,528**	**10,884**
Net Plant Electrical Output	kw	**300,280**	**300,373**	**292,576**
Net Plant Electrical Heat Rate, LHV	Btu/kWh_{net} (LHV)	**6,697**	**6,832**	**6,988**
Stack Diameter	ft	19.0	19.0	19.0
Flow (total)	lb/hr	3,912,713	3,514,130	3,260,979
Velocity	ft/sec	69.4	62.6	58.7
Temperature	^{o}F	200	200	200
Flow (total)	acfm	1,180,657	1,065,424	997,971
Flow (total)	scfm	884,127	797,836	747,324
Flow (total)	dscfm	808,711	716,344	651,161

2. PROJECT DESCRIPTION

Table 2-3
Deer Creek CT/HRSG Operating Parameters
Annual Average Ambient Conditions – Part Load Cases

Case		**Case 12**	**Case 13**	**Case 14**
Ambient Conditions		Annual Average	Annual Average	Annual Average
Ambient Temperature		43 oF	43 oF	43 oF
Combustion Turbine Load		75% CT Load	50% CT Load	25% CT Load
Duct Firing (Fired / Unfired)		Unfired	Unfired	Unfired
CT Power Output (per CT)	kW	124,600	83,100	41,500
CT Heat Consumption (per CT LHV)	mmBtu/hr	1,252.0	1,003.0	691.0
DB Heat Consumption (per HRSG LHV)	mmBtu/hr	0.0	0.0	0.0
Total Heat Input to CTs + HRSGs	mmBtu/hr	**1,252.0**	**1,003.0**	**691.0**
Gross Steam Turbine Output	kW	71,819	61,058	45,227
Total Gross Electrical Output	kW	**196,419**	**144,158**	**86,727**
Auxiliary Power	kW	**5,349**	**4,208**	**2,752**
Net Plant Electrical Output	kw	**191,070**	**139,950**	**83,975**
Net Plant Electrical Heat Rate, LHV	Btu/kWh_{net} (LHV)	**6,553**	**7,167**	**8,229**
Stack Diameter	ft	19.0	19.0	19.0
Flow (total)	lb/hr	2,780,100	2,285,080	1,826,055
Velocity	ft/sec	49.3	40.5	32.3
Temperature	^{o}F	200	200	200
Flow (total)	acfm	838,744	689,055	549,374
Flow (total)	scfm	628,088	515,994	411,396
Flow (total)	dscfm	577,778	475,953	383,668

2. PROJECT DESCRIPTION

Table 2-4
Deer Creek CT/HRSG Operating Parameters
Summer Average Maximum Ambient Conditions – Part Load Cases

Case		**Case 15**	**Case 16**	**Case 17**
Ambient Conditions		Summer	Summer	Summer
Ambient Temperature		94 oF	94 oF	94 oF
Combustion Turbine Load		75% CT Load	50% CT Load	25% CT Load
Duct Firing (Fired / Unfired)		Unfired	Unfired	Unfired
CT Power Output (per CT)	kW	105,200	70,100	35,100
CT Heat Consumption (per CT LHV)	mmBtu/hr	1,127.0	897.0	635.0
DB Heat Consumption (per HRSG LHV)	mmBtu/hr	0.0	0.0	0.0
Total Heat Input to CTs + HRSGs	mmBtu/hr	**1,127.0**	**897.0**	**635.0**
Gross Steam Turbine Output	kW	66,159	55,560	42,448
Total Gross Electrical Output	kW	**171,359**	**125,660**	**77,548**
Auxiliary Power	kW	**8,869**	**7,995**	**7,076**
Net Plant Electrical Output	kw	**162,490**	**117,665**	**70,472**
Net Plant Electrical Heat Rate, LHV	Btu/kWh_{net} (LHV)	**6,936**	**7,623**	**9,011**
Stack Diameter	ft	19.0	19.0	19.0
Flow (total)	lb/hr	2,567,091	2,162,072	1,750,051
Velocity	ft/sec	45.8	38.5	31.1
Temperature	^{o}F	200	200	200
Flow (total)	acfm	778,592	655,118	529,412
Flow (total)	scfm	583,044	490,581	396,447
Flow (total)	dscfm	528,938	447,263	364,335

2. PROJECT DESCRIPTION

2.2.3 Emergency Generator and Fire Water Pump

Deer Creek will have an emergency diesel generator (EDG) and emergency fire-water pump (FWP). The EDG will supply power to the essential service motor control centers during an interruption of the electrical power supply to the site, including building heat and fuel supply systems, plant communication systems, and essential emergency lighting. Based on preliminary design calculations, the EDG will be designed to provide 2,000 kW power during emergency situations, and the FWP will be designed at 577 hp to provide water at a rate of 3,000 gpm. The diesel engines will be designed to fire low-sulfur diesel fuel. Both engines will be used only in case of an emergency and for periodic testing.

2.2.4 Emergency Inlet Air Heater

The Deer Creek station will have one nature gas-fired emergency inlet heater to preheat the CT intake air under extremely cold ambient conditions (i.e., ambient temperatures less than approximately -25 °F). The heater will warm an ethylene glycol/water solution, which will be piped to a heat exchanger located at the CT air intake to heat the CT inlet air. The heater will operate for approximately 10 to 20 minutes during startup under extreme conditions. Once the CT is up to speed, the inlet air heater will be shut off and bleed heat from the compressor will be used to heat the inlet air. The emergency inlet heater design will be based on a maximum heat input of 25.0 mmBtu/hr to provide a heat duty of 19.0 mmBtu/hr, and will be designed to fire pipeline natural gas.

2.3 Emission Sources

Emission units at Deer Creek include the CT/HRSG, emergency generator, diesel fire-water pump, and emergency inlet air heater. A list of the emission sources is included in Table 2-5.

Table 2-5
Deer Creek Station – Emission Point Designations

Emission Source Designation	Emission Source Description
EP01	Combustion Turbine/HRSG
EP02	Emergency Generator
EP03	Fire Water Pump
EP04	Emergency Inlet Air Heater

2. PROJECT DESCRIPTION

2.4 General Applicant Information

The Deer Creek Station will be owned and operated by Basin Electric Power Cooperative. To facilitate DENR's review of this permit application, the individual most familiar with the proposed project and the permit application is identified below.

Project Owner Contact:

Mr. Jerry Menge
Basin Electric Power Cooperative
Air Quality Program Coordinator
1717 East Interstate Avenue
Bismarck, ND 58501

2.5 Standard Industrial Classification (SIC)

The United States government has devised a method for grouping all business activities according to their participation in the national commerce system. The system is based on classifying activities into "major groups" defined by the general character of a business operation. For example, electric, gas, and sanitary services, which include power production, are defined as a major group. Each major group is given a unique two digit number for identification. Power production activities have been assigned a major group code "49." To provide more detailed identification of a particular operation, an additional two-digit code is appended to the major group code. In the case of electric power generating facilities, the two digit code is "11" in order to define the type of production involved. Thus, the Deer Creek Station is classified under the SIC system as:

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

3. PROJECT EMISSIONS

3.0 Project Emissions

Emissions from the Deer Creek Station will be primarily the products of natural gas combustion in the CT and HRSG. The emergency generator, fire-water pump, and emergency inlet air heater will have limited use, but are also sources of emissions associated with fuel combustion. Emission sources at the facility are listed in Table 2-5.

Emission sources at the Deer Creek Station have the potential to emit the following NSR-PSD pollutants (i.e., pollutants for which PSD significance levels have been established in 40 CFR 52.21);

- Nitrogen oxides (NOx)
- Carbon monoxide (CO)
- Volatile organic compounds (VOC)
- Sulfur dioxide (SO_2)
- Particulate Matter (PM)
- PM with an aerodynamic diameter less than 10 microns (PM_{10})
- PM with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$)
- Sulfuric Acid Mist (H_2SO_4)

Emissions were calculated for each emissions source. For the CT/HRSG, performance calculations were prepared at various loads and ambient conditions to envelope potential operating scenarios and identify the maximum potential emission rates. NOx, CO, VOC, and filterable PM emissions were calculated based on emissions data available from CT and HRSG vendors. SO_2 emissions were calculated based on fuel flow to the combustion source, fuel sulfur content, and assuming 100% conversion of fuel sulfur to SO_2. Condensible PM emissions were calculated using emission factors provided in U.S.EPA's *Compilation of Air Pollution Emission Factors, Volume 1: Stationary Point and Area Sources,* (AP-42, Fifth Edition), and adding individual source-specific condensible constituents (e.g., sulfuric acid mist and/or ammonium sulfate). For natural gas combustion it was assumed that all of the PM would be emitted as $PM_{2.5}$ (see, e.g., AP-42 Table 1.4-2); therefore, the PM, PM_{10} and $PM_{2.5}$ emission rates are the same. Detailed emission calculations and methodologies used to calculate emissions are included in Appendix B of this permit application.

In addition to calculating potential PSD pollutant emissions, emission estimates were prepared for certain non-PSD pollutants, including pollutants defined hazardous air pollutants (HAPs) in Section 112 of the Clean Air Act. Potential HAP emissions were estimated for each emission source based on published emission factors in AP-42. HAP emission estimates are included in Section 3.5 of this permit application.

3. PROJECT EMISSIONS

Emission calculations were prepared for all emission sources at Deer Creek. Calculations were prepared for each potential emission source to determine: (1) emission rates during normal operation; (2) emission rates associated with startup of the combustion turbine; and (3) total annual emissions.

3.1 Combustion Turbine / HRSG Emissions

The CT/HRSG will be designed to fire pipeline natural gas. Natural gas characteristics used to calculate CT/HRSG performance and estimate potential emissions are included in Appendix B. CT/HRSG performance calculations were performed for several CT load levels, duct firing rates, and ambient conditions. CT/HRSG performance calculations for each operating scenario are also included in Appendix B. Emissions were calculated based on the BACT analysis (Appendix C) and emission rates achieved in practice by similar sources, anticipated vendor guarantees, and published emission factors.

During start-up, combustion turbines typically emit pollutants at rates (i.e., lb/mmBtu heat input) that are somewhat higher than the emission rates achieved during normal steady state operation. Emissions of NOx, CO, and VOC are expected to be somewhat higher during start-up of the Deer Creek CT than during normal operation. In addition, the proposed post-combustion control system (e.g., SCR for NOx control) will not effectively remove NOx when the exhaust gas temperature in the HRSG is below the minimum temperature required for effective operation. Emission calculations were prepared to account for increased emissions during CT startup. Startup emission calculations are included in Appendix B.

3.1.1 CT/HRSG Emissions During Normal Operations

CT/HRSG performance calculations were prepared for several CT load levels, duct firing rates, and ambient conditions. Operating parameters were calculated for the CTs at four load levels (100%, 75%, 50%, and 25%), and three ambient air temperatures (94 °F, 43 °F and -41 °F). These temperatures represent the summer maximum average temperature (94 °F), annual average temperature (43 °F), and winter extreme (-41 °F), as determined from weather data collected at local meteorological reporting stations. Operating parameters for duct burner firing were calculated for all of the 100% load cases. These operating cases cover the expected range of conditions in which Deer Creek CT/HRSG may operate at full load, and they bracket the expected worst-case air pollution emissions.

Table 3-1 summarizes the CT/HRSG performance calculations and emission estimates prepared for 100% load operation at each of the three ambient temperatures without supplemental duct firing.

3. PROJECT EMISSIONS

Maximum hourly emissions for each of the PSD pollutants are included. Table 3-2 provides a summary of the CT/HRSG emission calculations for each base load case with supplemental duct firing.

Maximum heat input to the CT of 1,713 mmBtu/hr occurs at the winter extreme ambient conditions. Maximum heat input to the duct burner (610.4 mmBtu/hr) occurs at summer ambient conditions, and is needed to boost total gross electrical output to 303 MW during extreme summer conditions. Maximum total heat input to the CT/HRSG of 2,052 mmBtu/hr occurs at the average annual ambient conditions when duct firing is used to achieve a total gross electrical output of 308.9 MW (1,541 mmBtu/hr heat input to CT and 511.1 mmBtu/hr heat input to the duct burner).

The emission estimates for the summer ambient conditions (94 °F) include duct burner firing to reflect worst-case operating conditions during periods of peak electricity demand. The emission estimates for the winter extreme conditions (-41°F) also include duct burner firing to reflect worst-case operating conditions during periods of winter peak electricity demand. The highest mass emission rates (lb/hr) for all pollutants occur at summer ambient conditions with duct firing. Maximum hourly mass emissions (lb/hr) from the Deer Creek CT/HRSG (with duct firing) are summarized in Table 3-3.

BASIN ELECTRIC POWER COOPERATIVE

3. PROJECT EMISSIONS

Table 3-1
Deer Creek Station CT/HRSG Emission
Base Load Without Supplemental Duct Firing

Emissions Summary				
Case		**Case 1**	**Case 3**	**Case 5**
		Winter Extreme Case	Annual Average	Summer
Ambient Temp / Load		-41 oF	43 oF	94 oF
		Base Load	Base Load	Base Load
Duct Firing (Fired / Unfired)		Unfired	Unfired	Unfired
Annual Hours of Operation (for permitting)	hours	8,760	8,760	8,760
CT Power Output (per CT)	kW	184,557	166,178	150,600
CT Heat Consumption (per CT LHV)	mmBtu/hr	1,713.0	1,541.0	1,434.0
DB Heat Consumption (per HRSG LHV)	mmBtu/hr	0.0	0.0	0.0
Total Heat Input to CTs + HRSGs	mmBtu/hr	**1,713.0**	**1,541.0**	**1,434.0**
Gross Steam Turbine Output	kW	85,326	83,505	79,936
Total Gross Electrical Output	kW	**269,883**	**249,683**	**230,536**
Auxiliary Power	kW	**5,390**	**6,507**	**10,001**
Net Plant Electrical Output	kw	**264,493**	**243,176**	**220,535**
Net Plant Electrical Heat Rate, LHV	Btu/kWh$_{net}$ (LHV)	**6,477**	**6,337**	**6,502**
Emissions (per CT/HRSG)		lb/hr	lb/hr	lb/hr
	NO_X	24.5	21.8	20.4
	CO	32.0	28.5	26.0
	VOC	3.07	2.74	2.55
	SO_2	2.71	2.44	2.27
	$PM_{10}/PM_{2.5}$ (filterable)	9.0	8.1	7.6
	Total $PM_{10}/PM_{2.5}$	18.6	16.7	15.7
	Sulfuric Acid Mist	0.49	0.45	0.42

BASIN ELECTRIC POWER COOPERATIVE

3. PROJECT EMISSIONS

Table 3-2
Deer Creek Station CT/HRSG Emission
Base Load With Supplemental Duct Firing

Emissions Summary				
Case		**Case 2**	**Case 4**	**Case 6**
		Winter Extreme Case	Annual Average	Summer
Ambient Temp / Load		-41 oF	43 oF	94 oF
		Base Load	Base Load	Base Load
Duct Firing (Fired / Unfired)		Duct Firing	Duct Firing	Duct Firing
Annual Hours of Operation (for permitting)	hours	8,760	8,760	8,760
CT Power Output (per CT)	kW	184,557	166,178	150,600
CT Heat Consumption (per CT LHV)	mmBtu/hr	1,713.0	1,541.0	1,434.0
DB Heat Consumption (per HRSG LHV)	mmBtu/hr	297.9	511.1	610.4
Total Heat Input to CTs + HRSGs	mmBtu/hr	**2,010.9**	**2,052.1**	**2,044.4**
Gross Steam Turbine Output	kW	122,116	142,723	152,860
Total Gross Electrical Output	kW	**306,673**	**308,901**	**303,460**
Auxiliary Power	kW	**6,393**	**8,528**	**10,884**
Net Plant Electrical Output	kw	**300,280**	**300,373**	**292,576**
Net Plant Electrical Heat Rate, LHV	Btu/kWh$_{net}$ (LHV)	**6,697**	**6,832**	**6,988**
Emissions (per CT/HRSG)		lb/hr	lb/hr	lb/hr
	NO_X	29.0	29.2	29.4
	CO	48.7	57.2	59.9
	VOC	9.68	14.13	16.10
	SO_2	3.18	3.25	3.24
	$PM_{10}/PM_{2.5}$ (filterable)	10.7	10.9	11.0
	Total $PM_{10}/PM_{2.5}$	22.3	22.9	23.2
	Sulfuric Acid Mist	0.58	0.60	0.59

3. PROJECT EMISSIONS

Table 3-3
Deer Creek Station CT/HRSG
Maximum Hourly Emissions

Pollutant	Emission Rate[(1)] (lb/hr)
NOx	29.4
CO	59.9
VOC	16.1
SO2	3.24
PM10 (filterable)	11.0
PM10 (total)	23.2
H_2SO_4[(2)]	0.59

(1) Emissions based on 1,434 mmBtu/hr heat input to the CT and 610.4 mmBtu/hr heat input to the duct burner at summer ambient conditions.
(2) To calculate emissions it was assumed that SO_3 formed in the CT/HRSG would react with ammonia slip to from ammonium sulfate, $(NH_4)_2SO_4$. $(NH_4)_2SO_4$ emissions are included in the calculation of condensible PM10. H_2SO_4 emissions were calculated assuming SO_3 reacted with water to form sulfuric acid mist.

3.1.2 Combustion Turbine Startup Emissions

During start-up, combustion turbines may emit certain pollutants at rates somewhat higher than the rates achieved during normal steady state operation. In addition, post-combustion control systems, such as the SCR system for NOx control, do not remove pollutants when the exhaust gas temperature in the HRSG is below the minimum temperature required for effective operation. Based on information available from combustion turbine vendors, emissions of NOx, CO, and VOC are expected to be somewhat higher during start-up of the combustion turbine. Emissions of other pollutants (e.g., SO_2 and particulate matter) are more a function of the fuel characteristics, and are not expected to be higher during startup.

One of the advantages of using a combined-cycle unit is its relatively short startup time and its ability to respond quickly to load changes. However, time is needed to stabilize the unit and ensure safe operation. The startup sequence includes multiple steps. In general, the combustion turbine is started and ramped-up to low load where it is held. Heat from the combustion turbine exhaust is used to bring the HRSG, steam piping, emissions control equipment, steam turbine, and other equipment to specified operating temperatures. The HRGS has three separate pressures sections, each with

3. PROJECT EMISSIONS

temperature increase rate limitations. Once the HRGS achieves the proper temperature, the steam turbine and its auxiliaries can be started and gradually heated as steam becomes available to drive the systems. Increases in steam turbine speed are constrained by the temperature differential between the metal surfaces and the steam and cannot be exceeded. Operating the systems within these constraints and vendor specified boundaries is required to protect the equipment and ensure safe operation of the system.

Startup of the gas turbine is generally independent of how long the unit was not in operation; however, the time required to startup the HRSG and steam turbine will vary depending upon how long the unit was shutdown. The HRSG and steam turbine require time to heat up and prepare for normal operation. The duration of a individual startup event will depend upon the amount of time since the unit's last period of normal operation. Depending upon how long it has been since the unit last operated, startups are generally classified as cold or warm startups or hot restarts. Startups for the Deer Creek combustion turbine will be classified as follows:

Startup Classification	Shutdown Period
Cold Startup	72-hour or longer
Warm Startup	greater than 48-hours but less than 72-hours
Hot Restart	greater than 8-hours but less than 48 hours

Based on startup information available from combined-cycle vendors, the duration of a cold startup will be approximately 200 minutes. This time is needed to start and ramp-up the gas turbine, as well as heat the HRSG and steam turbine, and startup, synchronize, and load the steam turbine. The duration of warm startups and hot restarts are somewhat shorter, at approximately 100 and 60 minutes, respectively.

Combustion conditions will continually vary throughout the duration of the startup, and can result in significantly higher short-term emission rates. Based on emissions information available from combustion turbine vendors, NOx concentrations can vary between approximately 60 and 120 ppmvd @ 15% O_2 during combustion turbine startup. CO concentrations may vary from approximately 100 to as high as 1,000 ppmvd for short periods of time.

Using representative startup curves provide by one of the potential combustion turbine vendors, BEPC calculated total NOx, CO, and VOC emissions associated with a cold, warm, and hot startup event. For these emission calculations, start-up was defined as the period from initial combustion of fuel in the combustion turbine to the combustion turbine reaching 50% of load and full operation of

3. PROJECT EMISSIONS

the SCR system. Detailed startup emission calculations are included in Appendix B, and are summarized in Tables 3-4 through 3-6.

Table 3-4
CT/HRSG Startup Emissions
Cold Startup

Cold Startup Emissions					
Pollutant	**Flame to FSNL**	**Initial Load to >50% Load**	**Total Emissions per Startup**	**Estimated Overall Startup Time**	**Average Startup Emission Rate**
	(lbs)	**(lbs)**	**(lbs)**	**(minutes)**	**(lb/hr)**
NOx	10.0	210.5	220.5	202	65.5
CO	250.0	586.7	836.7	202	248.5
VOC	14.0	35.1	49.1	202	14.6
PM10	0.16	8.11	8.27	202	2.46

Table 3-5
CT/HRSG Startup Emissions
Warm Startup

Warm Startup Emissions					
Pollutant	**Flame to FSNL**	**Initial Load to >50% Load**	**Total Emissions per Startup**	**Estimated Overall Startup Time**	**Average Startup Emission Rate**
	(lbs)	**(lbs)**	**(lbs)**	**(minutes)**	**(lb/hr)**
NOx	10.0	77.9	87.9	98	53.8
CO	250.0	300.6	550.6	98	337.1
VOC	14.0	16.2	30.2	98	18.5
PM10	0.16	3.10	3.26	98	2.00

3. PROJECT EMISSIONS

Table 3-6
CT/HRSG Startup Emissions
Hot Restart

Hot Re-Start Emissions					
Pollutant	**Flame to FSNL**	**Initial Load to >50% Load**	**Total Emissions per Startup**	**Estimated Overall Startup Time**	**Average Startup Emission Rate**
	(lbs)	**(lbs)**	**(lbs)**	**(minutes)**	**(lb/hr)**
NOx	10.0	56.2	66.2	63	63.0
CO	250.0	96.6	346.6	63	330.1
VOC	14.0	5.2	19.2	63	18.3
PM10	0.17	1.79	1.96	63	1.87

The Deer Creek combined-cycle unit is being designed to follow changes in demand for electricity, and to provide more electricity during periods of high demand. Therefore, it is anticipated that the CT/HRSG will be subject to frequent load changes and startups. Based on a review of anticipated market conditions and historical demand curves, it is anticipated that the CT/HRSG will be subject to approximately 75 cold starts, 260 warm starts, and 30 hot re-starts each year. An estimate of the time the CT/HRSG will operate in each startup mode (hours per year) is provided in Table 3-7. Total NOx, CO, and VOC emissions associated with CT/HRSG startups are summarized in Tables 3-8, 3-9, and 3-10, respectively.

Table 3-7
CT/HRSG Startup Emissions
Estimated Startup Hours per Year

Estimated Number of Startups/Re-Starts per Year			
Startup Mode	**Number of Startups per Year**	**Time per Startup**	**Hours per Year**
	(#)	**(hours)**	**(hours)**
Cold Startup	75	3.37	252.8
Warm Startup	260	1.63	423.8
Hot Re-Start	30	1.05	31.5
Total Startup Hours per Year			708.1

3. PROJECT EMISSIONS

Table 3-8
CT/HRSG Startup Emissions
Estimated Startup Emissions – NOx

NOx Emissions	Average Startup Emission Rate (lb/hr)	Startup Hours per Year (hr/year)	Annual Startup Emissions (tpy)
Cold Startups	65.5	252.8	8.28
Warm Startups	53.8	423.8	11.4
Hot Re-Starts	63.0	31.5	0.99
Total Startup Emissions			20.7

Table 3-9
CT/HRSG Startup Emissions
Estimated Startup Emissions – CO

CO Emissions	Average Startup Emission Rate (lb/hr)	Startup Hours per Year (hr/year)	Annual Startup Emissions (tpy)
Cold Startups	248.5	252.8	31.4
Warm Startups	337.1	423.8	71.4
Hot Re-Starts	330.1	31.5	5.20
Total Startup Emissions			108.0

Table 3-10
CT/HRSG Startup Emissions
Estimated Startup Emissions – VOC

VOC Emissions	Average Startup Emission Rate (lb/hr)	Startup Hours per Year (hr/year)	Annual Startup Emissions (tpy)
Cold Startups	14.6	252.8	1.84
Warm Startups	18.5	423.8	3.92
Hot Re-Starts	18.3	31.5	0.29
Total Startup Emissions			6.05

3. PROJECT EMISSIONS

3.1.3 Annual CT/HRSG Emissions

Annual emissions from the CT/HRSG will be a combination of combustion turbine emissions, duct burner emissions, and emissions associated with unit startup. Potential annual emissions were calculated for the Deer Creek CT/HRSG based on the following assumptions:

- 708 hours per year in the startup mode (Table 3-7);
- 2,200 hours per year at 41°F with 100% CT load and maximum duct burner firing; and
- 5,852 hours (all the remaining hours in a year) of operation at 41 °F with 100% CT load with no duct firing.

Potential emissions calculated using the foregoing assumptions are summarized in Table 3-11. These emission estimates are considered conservative for the following reasons:

- Deer Creek probably will never operate continuously at 100% load for all of the hours in a year. Any periods of no operation or operation at lower loads will decrease the total annual emissions.
- Since duct burner firing normally will occur during the summer, much of the operating time in that condition will occur at ambient temperatures higher than 41 °F. Mass emission rates will be lower during operation at higher temperatures.

Table 3-11
Deer Creek CT/HRSG Annual Emissions Summary (tpy)

Operating Mode	NOx	CO	VOC	PM (filterable)	PM (total)	SO2	H2SO4
Full Load Operation without Duct Firing	63.8	83.4	8.0	26.6	54.8	8.0	1.5
Full Load Operation with Duct Firing	32.1	62.9	15.5	12.0	25.2	3.6	0.7
Startup Emissions	20.7	108.0	6.1	--	--	--	--
Total Annual Emissions	116.6	254.3	29.6	38.6	80.0	11.6	2.2

* Emissions of PM, SO_2, and H_2SO_4 are not expected to change appreciably during startup; therefore, total annual emissions for these pollutants were calculated assuming 2,200 hr/yr duct firing and 6,560 hr/year at full load without duct firing. Emissions of other PSD pollutants, including fluorides and lead are expected to be negligible.

3. PROJECT EMISSIONS

3.2 Emergency Generator and Diesel Fire-Water Pump Emissions

Deer Creek will also have an emergency diesel generator (EDG) and emergency fire-water pump (FWP). Based on preliminary design calculations, the EDG will be designed to provide 2,000 kW power during emergency situations, and the FWP will be designed at 577 hp to provide water at a rate of 3,000 gpm. The size of the EDG and FWP may change during final design of the facility; however, the sizes described above are considered conservatively large, and any change should result is less emissions.

The diesel engines will be designed to fire low-sulfur diesel fuel. Emissions from the diesel engines will be controlled by firing low-sulfur fuels, using combustion controls, and limiting the annual hours of operation to 150 hours per year. Both engines will be used only in case of an emergency and for periodic testing. Potential emissions from the EDG and FWP are summarized in Tables 3-12 and 3-13, respectively.

Table 3-12
Emergency Diesel Generator Emissions (controlled)

Pollutant	Emission Factor	Hourly Emissions(1)	Annual Emissions @ 150 hr/yr
		lb/hr	tpy
NMHC + NOx(2)	4.77 g/hp-hr (output)	30.7	2.3
NOx	4.48 g/hr-hr (output)	28.9	2.2
CO	2.61 g/hp-hr (output)	16.8	1.3
VOC(2)	0.0819 lb/mmBtu (heat input)	1.85	0.14
PM/PM_{10}	0.15 g/hp-hr	0.97	0.07
SO_2	0.051 lb/mmBtu (heat input)	1.15	0.09
H2SO4	0.004 lb/mmBtu (heat input)	0.088	0.007

(1) Hourly emission rates were calculated assuming a generator output of 2,000 kW and a maximum heat input to the diesel engine of 22.53 mmBtu/hr. Annual emissions were calculated based on 150 hours per year.
(2) NMHC+NOx emissions were calculated based on the combustion ignition internal combustion engine new source performance standard of 4.77 g/hp-hr. VOC emissions were calculated based on the applicable AP-42 emission factor for large diesel engines (AP-42 Table 3.4-1). NOx emissions were calculated by subtracting VOC emissions from NMHC+NOx emissions.

3. PROJECT EMISSIONS

Table 3-13
Fire-Water Pump Emissions (controlled)

Pollutant	Emission Factor	Hourly Emissions[1] lb/hr	Annual Emissions @ 150 hr/yr tpy
NMHC + NOx[2]	3.0 g/hp-hr (output)	3.82	0.29
NOx	1.9 g/hr-hr (output)	2.39	0.18
CO	2.6 g/hp-hr	3.31	0.25
VOC[2]	2.47 x 10^{-3} lb/hp-hr (output)	1.43	0.11
PM/PM_{10}	0.15 g/hp-hr	0.19	0.014
SO_2	0.052 lb/mmBtu (heat input)	0.23	0.02
H2SO4	0.004 lb/mmBtu (heat input)	0.018	0.001

(1) Hourly emission rates were calculated assuming a diesel engine output of 577 hp and a maximum heat input of 4.45 mmBtu/hr. Annual emissions were calculated based on 150 hours per year.
(2) NMHC+NOx emissions were calculated based on the combustion ignition internal combustion engine new source performance standard of 3.0 g/hp-hr. VOC emissions were calculated based on the applicable AP-42 emission factor for diesel-fired engines (AP-42 Table 3.3-1). NOx emissions were calculated by subtracting VOC emissions from NMHC+NOx emissions.

3.3 Emergency Inlet Air Heater

The Deer Creek station will have one nature gas-fired emergency air inlet heater to preheat the CT intake air under extreme cold (approximately -25 °F) conditions. The heater will warm a water and ethylene glycol mixture, which will be piped to the CT air intake to heat the air entering the turbine. The heater will operate for 10-20 minutes during startup under extreme conditions. Once the CT is up to speed, the inlet air heater will be shut off and bleed heat off the compressor will take over. The heater design will be based on a maximum heat input of 25.0 mmBtu/hr used to provide a heat duty of 19.0 mmBtu.

The emergency inlet air heater will be designed to fire pipeline natural gas. Emissions from the heater will be controlled by using combustion controls and limiting the annual hours of operation to 150 hours per year. Potential emissions from the emergency inlet air heater are summarized in Tables 3-14.

3. PROJECT EMISSIONS

Table 3-14
Emergency Inlet Air Heater Emissions

Pollutant	Emission Factor	Hourly Emissions(1) lb/hr	Annual Emissions @ 150 hr/yr tpy
NOx	50 lb/mmscf	1.23	0.09
CO	84 lb/mmscf	2.06	0.15
VOC	5.5 lb/mmscf	0.13	0.01
PM/PM_{10}	7.6 lb/mmscf	0.19	0.01
SO_2	0.714 lb/mmscf	0.02	0.002
H2SO4	0.055 lb/mmscf	0.001	0.000075

(1) Hourly emission rates were calculated assuming a maximum heat input of 25.0 mmBtu/hr and AP-42 natural gas emission factors (AP-42 Table 1.4-1). Annual emissions were calculated based on 150 hours per year.

3.5 Potential Annual Emissions

Potential annual emissions from all emission sources at the Deer Creek Station are summarized in Table 3-15.

Table 3-15
Annual Potential-to-Emit (PTE) Summary

Pollutant	CT/HRSG	Emergency Generator	Fire-Water Pump	Emergency Inlet Heater	Total
	tpy	tpy	tpy	tpy	tpy
NO_x	116.6	2.2	0.18	0.09	**119.1**
CO	254.3	1.3	0.25	0.15	**256.0**
VOC	29.6	0.14	0.11	0.010	**29.7**
PM (filterable)	38.6	0.07	0.014	0.004	**38.7**
PM Total(1)	80.0	0.07	0.014	0.014	**80.1**
SO_2	11.6	0.09	0.02	0.002	**11.7**
H_2SO_4(1)	2.2	0.007	0.001	0.000075	**2.21**
Lead(1)	3.59×10^{-4}	neg.	neg.	9.38×10^{-7}	**3.60×10^{-4}**

(1) Total PM10 includes filterable and condensible constituents. Condensible emissions are assumed to include ammonium sulfate emissions from the CT/HRSG.
(2) Sulfuric acid mist emissions from the CT/HRSG were calculated assuming SO_3 formed during the combustion process reacts with water to form H_2SO_4. To calculate emissions from the CT/HRSG it was also assumed that SO_3 formed in the CT/HRSG would react with ammonia slip to from ammonium sulfate, $(NH_4)_2SO_4$. $(NH_4)_2SO_4$ emissions were included in the calculation of condensible PM10.
(3) Emission rates designated as "neg." are considered to be negligible or were not calculated because of the lack of an applicable AP-42 emission factor.

3. PROJECT EMISSIONS

3.6 Potential Emissions of Non-PSD Pollutants

Emissions of non-PSD pollutants, including pollutants defined as hazardous air pollutants (HAPs) in section 112 of the Clean Air Act, were estimated based on fuel characteristics, heat input to each combustion source, and the applicable AP-42 emissions factors.

Potential HAP emissions from the CT/HRSG are summarized in Table 3-16. HAP emissions from the emergency generator, diesel fire-pump, and inlet air heater are summarized in Table 3-17. Total potential annual HAP emissions are summarized in Table 3-18. Detailed HAP emission calculations for each emission source, including references to the emissions factors used, are included in Appendix B.

Table 3-16
Deer Creek CT/HRSG – Potential HAP Emissions

TRACE METAL HAP EMISSIONS	Combustion Turbines		Duct Firing		Total	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Arsenic	0.00E+00	0.00E+00	1.20E-04	1.44E-04	1.20E-04	1.44E-04
Beryllium	0.00E+00	0.00E+00	7.18E-06	8.61E-06	7.18E-06	8.61E-06
Cadmium	0.00E+00	0.00E+00	6.58E-04	7.89E-04	6.58E-04	7.89E-04
Chromium	0.00E+00	0.00E+00	8.37E-04	1.00E-03	8.37E-04	1.00E-03
Cobalt	0.00E+00	0.00E+00	5.02E-05	6.03E-05	5.02E-05	6.03E-05
Lead	0.00E+00	0.00E+00	2.99E-04	3.59E-04	2.99E-04	3.59E-04
Manganese	0.00E+00	0.00E+00	2.27E-04	2.73E-04	2.27E-04	2.73E-04
Mercury	0.00E+00	0.00E+00	1.55E-04	1.87E-04	1.55E-04	1.87E-04
Nickel	0.00E+00	0.00E+00	1.26E-03	1.51E-03	1.26E-03	**1.51E-03**
Selenium	0.00E+00	0.00E+00	1.44E-05	1.72E-05	1.44E-05	1.72E-05
Total HAP Metal Emissions	0.0000	0.0000	0.0036	0.0043	0.0036	0.0043
ORGANIC HAP EMISSIONS	**Combustion Turbines**		**Duct Firing**		**Total**	
	(lb/hr)	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
Napthalene	1.86E-03	8.17E-03	0.00E+00	0.00E+00	1.86E-03	8.17E-03
2-Methylnaphthalene*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoranthene*	0.00E+00	0.00E+00	1.26E-03	1.51E-03	1.26E-03	1.51E-03
Fluorene*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Phenananthrene*	0.00E+00	0.00E+00	4.49E-02	5.38E-02	4.49E-02	5.38E-02
Pyrene*	0.00E+00	0.00E+00	2.03E-03	2.44E-03	2.03E-03	2.44E-03
Total PAH (Note 2)	3.15E-03	1.38E-02	0.00E+00	0.00E+00	3.15E-03	1.38E-02
Acetaldehyde	5.74E-02	2.51E-01	0.00E+00	0.00E+00	5.74E-02	2.51E-01
Acrolein	9.18E-03	4.02E-02	0.00E+00	0.00E+00	9.18E-03	4.02E-02
Benzene	1.72E-02	7.54E-02	1.26E-03	1.51E-03	1.85E-02	7.69E-02
Ethylbenzene	4.59E-02	2.01E-01	0.00E+00	0.00E+00	4.59E-02	2.01E-01
Formaldehyde	1.02E+00	4.46E+00	4.49E-02	5.38E-02	1.06E+00	**4.51E+00**
Toluene	1.86E-01	8.17E-01	2.03E-03	2.44E-03	1.88E-01	8.19E-01
Xylene	9.18E-02	4.02E-01	0.00E+00	0.00E+00	9.18E-02	4.02E-01
Dichlorobenzene	0.00E+00	0.00E+00	7.18E-04	8.61E-04	7.18E-04	8.61E-04
Hexane	0.00E+00	0.00E+00	1.08E+00	1.29E+00	1.08E+00	1.29E+00
Total Organic HAP Emissions	1.43	6.26	1.13	1.35	2.55	7.61
Total HAP Emissions per CT/HRSG	1.43	6.26	1.134	1.354	2.55	7.61

3. PROJECT EMISSIONS

Table 3-17
Auxiliary Combustion Sources – HAP Emission Summary

Source	Metal HAPs	Organic HAPs	Total HAP Emissions
	tpy	tpy	tpy
Emergency Diesel Generator	--	2.5×10^{-3}	2.5×10^{-3}
Fire Water Pump	--	2.1×10^{-3}	2.1×10^{-3}
Emergency Inlet Air Heater	1.1×10^{-5}	3.5×10^{-3}	3.5×10^{-3}
Total	$\mathbf{1.1 \times 10^{-5}}$	$\mathbf{8.1 \times 10^{-3}}$	$\mathbf{8.1 \times 10^{-3}}$

Table 3-18
Deer Creek Potential Annual HAP Emissions*

Source	Total HAP Emissions
	tpy
CT/HRSG	7.61
Emergency Diesel Generator	2.5×10^{-3}
Fire Water Pump	2.1×10^{-3}
Emergency Inlet Air Heater	3.5×10^{-3}
Total	**7.62**

3. PROJECT EMISSIONS

3.6 Insignificant Activities

Insignificant activities that are excluded from the South Dakota Part 70 operating permit requirements are defined in subsection 74:36:05:04.01. Operation of the Deer Creek Station may include the following insignificant activities:

Combustion Equipment

- Mobile internal combustion engines, including engines in autos, trucks, and tractors;
- Laboratory equipment used exclusively for chemical or physical analysis;
- A device or apparatus that has a heat input capability of not more than 3.5 mmBtu/hr;
- An air conditioning or ventilating system not designed to remove air pollutants from equipment;
- Routine housekeeping or plant upkeep activities such as painting buildings, re-tarring roofs, or paving parking lots;
- A unit that has the potential to emit two tons or less per year of any criteria pollutant before the application of control equipment. A unit may not be considered insignificant if a state or federal limit is applicable to the unit; and
- A unit that has the potential to emit two tons or less per year of any hazardous air pollutant. However, the hazardous air pollutant emissions from the unit must be included in determining if the source is a major or minor source. A unit cannot be considered insignificant if a state or federal limit is applicable to the unit.

Potential insignificant activities associated with the Deer Creek project include diesel storage tanks for the emergency generator and fire water pump, as well as lubricating oil storage tanks associated with the CT/HRSG.

4. REGULATORY REVIEW

4.0 Introduction

This section reviews air quality regulations governing the construction and operation of the Deer Creek Station. The following State and Federal air quality regulations were evaluated for applicability to the proposed project:

- South Dakota Air Pollution Control Program – Administrative Rules of South Dakota Regulations Article 74:36
- National Ambient Air Quality Standards
- New Source Review Permitting Requirements, including Prevention of Significant Deterioration and Non-Attainment New Source Review
- New Source Performance Standards
- National Emission Standards for Hazardous Air Pollutants
- Federal Acid Rain Program (40 CFR Parts 72, 73, 74, 75, and 76)
- Compliance Assurance Monitoring (40 CFR Part 64)

4.1 Overview of Air Quality Regulations

The Federal Clean Air Act, as amended (CAA), mandated U.S.EPA to establish national ambient air quality standards (NAAQS) for specific pollutants, and required each state to develop a state implementation plan (SIP) to attain and maintain the NAAQS within the state. EPA evaluates each states' SIP, and, upon approval, publishes a notice of approval in the Federal Register which is then codified in the Code of Federal Regulations (CFR) at 40 CFR Part 52. The State of South Dakota has developed a SIP, and has been granted authorization to implement and enforce regulations governing the permitting and operation of air emission sources. (40 CFR Part 52 Subpart QQ).

Federal regulations promulgated pursuant to the CAA are codified in Title 40 of the Code of Federal Regulations (40 CFR). The South Dakota air pollution control regulations are in Article 74:36 of the Administrative Rules of South Dakota (ARSD). Both Federal and South Dakota regulations require new major stationary sources of air pollution to undergo review and obtain a permit before commencing construction. In addition to the pre-construction permitting requirements, Federal and State regulations include new source performance standards (NSPS), national emission standards for hazardous air pollutants (NESHAPs), and standards governing the emission of pollutants that contribute to the formation of acid rain. A summary of the air emission standards applicable to the Deer Creek Station is provided below.

4. REGULATORY REVIEW

4.2 South Dakota Air Emission Standards

The South Dakota air pollution control regulations are codified in ARSD Article 74:36 (Air Pollution Control Program). A summary of the applicable State regulations is provided below.

4.2.1 Chapter 74:36:01 – Definitions

Chapter 74:36:01 of the South Dakota air pollution control program includes the definition of terms used throughout Article 74:36.

4.2.2 Chapter 74:36:02 – Ambient Air Quality

The CAA mandated the U.S.EPA to establish NAAQS for certain criteria pollutants. Pursuant to this mandate, U.S.EPA established NAAQS for criteria pollutants including CO, NOx, SO_2, PM_{10}, $PM_{2.5}$, ozone (regulated as volatile organic compounds), and lead. Geographic areas that meet the NAAQS for a given pollutant are classified as “attainment” areas, while those that do not meet the NAAQS are classified as “non-attainment” areas. Areas where there is insufficient monitoring data to determine whether the area has attained the NAAQS are designated as “unclassifiable,” however, these areas are treated as attainment areas for permitting purposes.

U.S.EPA recently finalized revisions to the NAAQS for ozone and particulate matter. The existing 8-hour ozone NAAQS (0.08 ppm) was replaced with a more stringent 0.075 ppm 8-hour average standard. The primary particulate matter standard was revised to include two new standards for fine particles (generally referring to particles less than or equal to 2.5 micrometers (μm) in diameter, $PM_{2.5}$), and a more stringent PM_{10} standard. EPA revised the level of the 24-hour $PM_{2.5}$ standard from 65 $\mu m/m^3$ to 35 $\mu g/m^3$ and retained the level of the annual $PM_{2.5}$ standard at 15 $\mu g/m^3$. With regard to the PM_{10} standards, EPA retained the 24-hour PM_{10} NAAQS and revoked the annual PM_{10} standard.

Chapter 74:36:02 incorporates, by reference, the ambient air quality standards listed in 40 CFR Part 50. The primary and secondary ambient air quality standards are summarized in Table 4-1.

4. REGULATORY REVIEW

Table 4-1
National Ambient Air Quality Standards

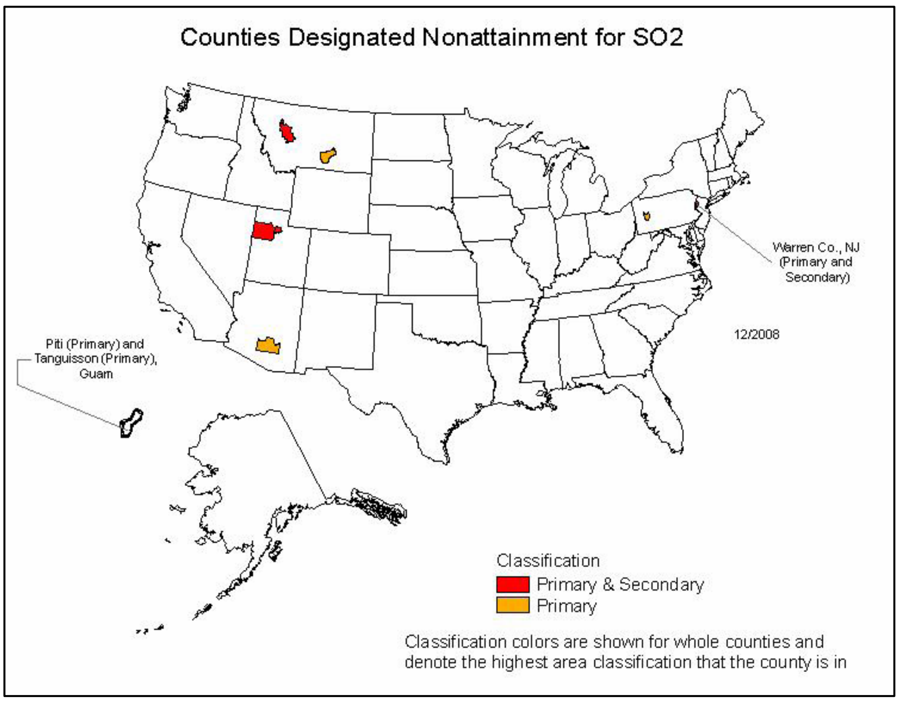
	Primary Standards		**Secondary Standards**	
Pollutant	**Level**	**Averaging Time**	**Level**	**Averaging Time**
Carbon Monoxide	9 ppm (10 mg/m^3)	8-hour [1]	None	
	35 ppm (40 mg/m^3)	1-hour [1]		
Lead	0.15 µg/m^3 [2]	Rolling 3-Month Average	Same as Primary	
	1.5 µg/m^3	Quarterly Average	Same as Primary	
Nitrogen Dioxide	0.053 ppm (100 µg/m^3)	Annual (Arithmetic Mean)	Same as Primary	
Particulate Matter (PM_{10})	150 µg/m^3	24-hour [3]	Same as Primary	
Particulate Matter ($PM_{2.5}$)	15.0 µg/m^3	Annual [4] (Arithmetic Mean)	Same as Primary	
	35 µg/m^3	24-hour [5]	Same as Primary	
Ozone	0.075 ppm (2008 std)	8-hour [6]	Same as Primary	
	0.08 ppm (1997 std)	8-hour [7]	Same as Primary	
	0.12 ppm	1-hour [8] (Applies only in limited areas)	Same as Primary	
Sulfur Dioxide	0.03 ppm	Annual (Arithmetic Mean)	0.5 ppm (1300 µg/m^3)	3-hour [1]
	0.14 ppm	24-hour [1]		

(1) Not to be exceeded more than once per year.
(2) Final rule signed October 15, 2008.
(3) Not to be exceeded more than once per year on average over 3 years.
(4) To attain this standard, the 3-year average of the weighted annual mean PM2.5 concentrations from single or multiple community-oriented monitors must not exceed 15.0 µg/m3.
(5) To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 µg/m3 (effective December 17, 2006).
(6) To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm. (effective May 27, 2008)
(7) (a) To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm.
(b) The 1997 standard—and the implementation rules for that standard—will remain in place for implementation purposes as EPA undertakes rulemaking to address the transition from the 1997 ozone standard to the 2008 ozone standard.
(8) (a) The standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is ≤ 1.
(b) As of June 15, 2005 EPA revoked the 1-hour ozone standard in all areas except the 8-hour ozone nonattainment Early Action Compact (EAC) Areas.

4. REGULATORY REVIEW

In order to implement the NAAQS, each State was required to use air monitoring data to designate areas within the State that do not meet the standards, and provide this information as a recommendation to EPA for its non-attainment area designations. Shown in figures 4-1 thorough 4-3 are the designated nonattainment areas for SO_2, 8-hour ozone, and $PM_{2.5}$.

Figure 4-1
Counties Designated Nonattainment for the SO_2 NAAQS



4. REGULATORY REVIEW

Figure 4-2
Counties Designated Nonattainment for the 8-hour Ozone NAAQS

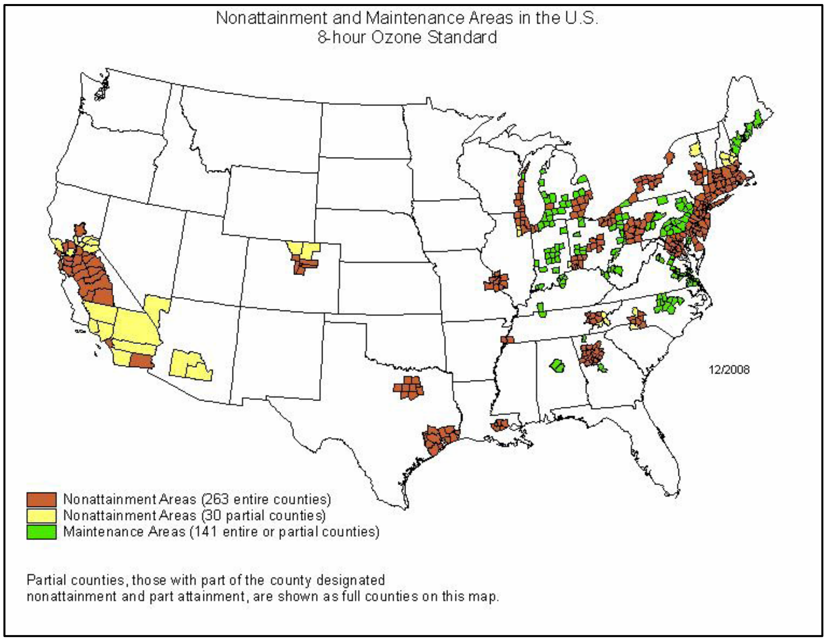
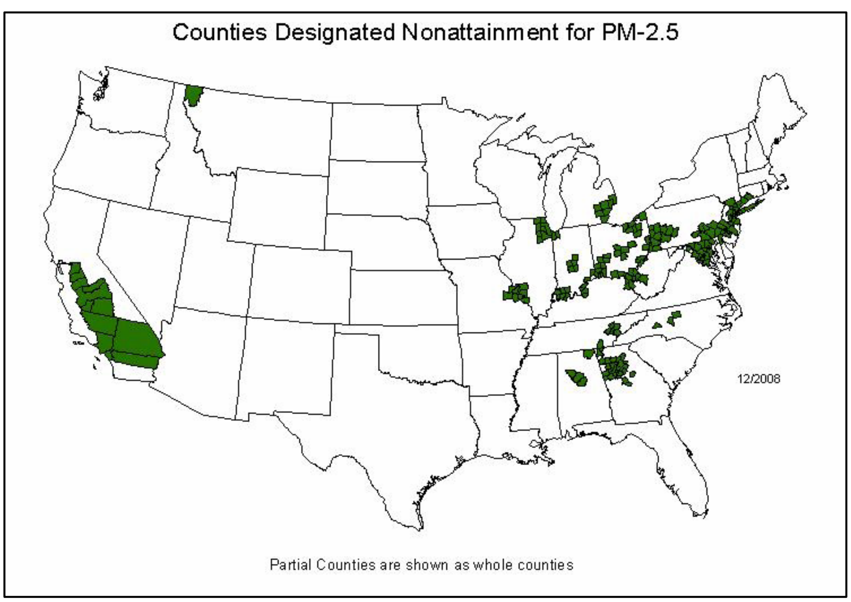


Figure 4-1
Counties Designated Nonattainment for the $PM_{2.5}$ NAAQS



4. REGULATORY REVIEW

The Deer Creek Station will be constructed in Brookings County South Dakota. Currently all counties in South Dakota are classified as attainment or unclassifiable for all ambient air quality standards.

In addition to establishing the NAAQS, EPA also established Prevention of Significant (PSD) increment levels. A PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a given criteria pollutant. The baseline concentration is defined for each pollutant and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area was submitted. PSD increments are applicable to units located within attainment areas, and are designed to prevent the air quality in the attainment area from deteriorating to a level set by the NAAQS. The PSD allowable increments are summarized in Table 4-2.

Table 4-2
Allowable PSD Increments and Significant Impact Levels ($\mu g/m^3$)

Pollutant	Averaging Time	PSD Increments		Significant Impact Levels
		Class I	Class II	Class II
PM10	Annual Arithmetic Mean	4	17	1
	24-hour Maximum	8	30	5
SO_2	Annual Arithmetic Mean	2	20	1
	24-hour Maximum	5	91	5
	3-hour Maximum	25	512	25
CO	8-hour Maximum	NA	NA	500
	1-hour Maximum	NA	NA	2,000
NO_x	Annual Arithmetic Mean	2.5	25	1

NA = Not applicable – no standard exists for this pollutant and averaging time.
Source: 40 CFR 52.21, 40 CFR 51.165

4.2.3 Chapter 74:36:03 – Air Quality Episodes

Chapter 74:36:03 incorporates by reference regulations included in 40 CFR 50.151 and 50.152, requiring the DENR to develop and maintain an episode emergency contingency plan, and use the criteria in 40 CFR 51.151 and Appendix L to Part 51, to proclaim an air pollution emergency episode if the accumulation of air pollutants in any place is attaining or has attained levels which could, if such levels are sustained or exceeded, lead to a substantial threat to the health of the public.

4. REGULATORY REVIEW

4.2.4 Chapter 74:36:04 - Operating Permits for Minor Sources

Regulations in Chapter 74:36:04 state that "[a] person may not construct, install, modify, or operate any source or unit likely to cause the emission of air pollutants into the ambient air or any equipment which prevents or controls the emission of air pollutants into the ambient air until the applicable preconstruction permit or operating permit has been issued by the board or the secretary." The provisions in Chapter 74:36:04 apply to minor emission sources. The term "minor source" is defined in Chapter 74:36:01 as "a source whose potential emissions of a criteria pollutant are less than 100 tons a year and which does not meet the definition of a Part 70 source." As discussed below, the Dry Creek Station will meet the definition of a Part 70 source; therefore, the minor source permitting requirements in Chapter 74:36:04 are not applicable to this project.

4.2.5 Chapter 74:36:05 - Operating Permits for Part 70 Sources

Regulations in Chapter 74:36:05.02 state that "[a] person may not construct, install, modify, revise, or operate any source or unit likely to cause the emission of air pollutants into the ambient air or any equipment which prevents or controls the emission of air pollutants into the ambient air until the applicable preconstruction permit or Part 70 operating permit has been issued by the board or the secretary."

The provisions in Chapter 74:36:05 apply to all sources required to obtain a Part 70 operating permit. Sources required to obtain a Part 70 operating permit include:

1) Any major source;
2) Any source, including an area source, subject to a standard or regulation promulgated under §111 of the Clean Air Act;
3) Any source, including an area source, subject to a standard or regulation promulgated under §112 of the Clean Air Act, except for a source that is solely subject to the regulations or requirements of §112(r);
4) Any affected source subject to Title IV of the Clean Air Act; and
5) Any source in a source category designated by the administrator of the EPA through the Clean Air Act pursuant to Title V of the Clean Air Act.

As discussed below (subsection 4.2.9), the Deer Creek Station meets the definition of a major source. Therefore, the facility will be subject to the Chapter 74:36:05 Operating Permit requirements. Provisions in 74:36:05:03.01 state that "[t]he submittal of a complete application for an operating permit for a Part 70 source does not affect the requirement that a source have a PSD or NSR preconstruction permit as required under §110, 165, 172, or 173 of the Clean Air Act or chapters 74:36:09 and 74:36:10. A PSD or NSR source must submit a complete application for a Part 70 operating permit within 12 months after commencing operation."

The Deer Creek Station will be subject to the PSD permitting requirements in chapter 74:36:09 (see, subsection 4.2.9), and will be required to obtain a PSD air construction permit prior to commencing construction of the facility. This permit application is the facility's PSD air construction permit application. In accordance with the requirements in Chapter 74:36:05:03.01, the facility will be required to submit a Part 70 operating permit application within 12 months after commencing operation.

4.2.6 Chapter 74:36:06 - Regulated Air Pollutant Emissions

The provisions in Chapter 74:36:06:01 state that "any unit required to be permitted under [Article 74:36] must comply with the standards and requirements in this chapter except as otherwise specified in chapter 74:36:07, 74:36:09, 74:36:09, 74:36:10, or 74:36:16." The Deer Creek Station will be required to be permitted under Article 74:36:09 (Prevention of Significant Deterioration) and will be subject to the emission standards in Chapter 74:36:06. Emission standards in Chapter 74:36:06 are summarized below:

4.2.6.1 Subchapter 74:36:06:02 – Allowable Emissions for Fuel-Burning Units

Subchapter 74:36:06:02 includes the following emission limits applicable to the owner/operator of a fuel-burning unit. The term "fuel-burning unit" is defined in chapter 74:36:01 to include "a furnace, boiler, apparatus, stack, or any of their components used in the process of burning fuel or other combustible material for the primary purposes of producing heat or power by indirect heat transfer." Based on the definition of "fuel-burning unit" these emission standards apply to the combustion turbine, duct burners, emergency diesel generator, fire-water pump, and emergency inlet air heater at the Deer Creek Station.

Particulate Matter:

(a) A fuel-burning unit with a heat input values less than 10 mmBtu/hr may not exceed 0.6 pounds of particulate matter per million Btu heat input.

4. REGULATORY REVIEW

(b) A fuel-burning unit with a heat input equal to or greater than 10 mmBtu/hr may not exceed the particulate emissions rate determined by the following equation:

$E = 0.811H^{-0.131}$, where
E = allowable particulate emissions rate in lb/mmBtu heat input; and
H = heat input in mmBtu/hr

A comparison of the particulate emission standards to the proposed Deer Creek emission limits is provided in Table 4-3. All of the proposed emission sources will meet the applicable 74:36:06:02 particulate emission limit.

Table 4-3
Summary of Applicable South Dakota Particulate Emission Limitations

Case	Maximum Design Heat Input (mmBtu/hr)	Applicable PM Emission Limit (lb/mmBtu)	Calculated PM Emission Limit (lb/mmBtu)
Fire-Water Pump	4.45	0.60	0.043
Emergency Diesel Generator	22.5	0.54	0.043
Emergency Inlet Air Heater	25.0	0.53	0.0076
CT/HRSG	2044.4	0.30	0.011

Provision 74:36:06:02(2) states that "[a] fuel-burning unit may not emit sulfur dioxide emissions to the ambient air in an amount greater than three pounds of sulfur dioxide per million Btu heat input to the unit based on a three-hour rolling average, which is the arithmetic average of three contiguous one-our periods." Because of the low sulfur content of natural gas and diesel fuel, SO_2 emissions from the fuel-burning units at the Deer Creek Station will be significantly below the 3.0 lb/mmBtu standard.

4.2.7 Chapter 74:36:07 – New Source Performance Standards

Chapter 74:36:07 establishes state standards for certain new or modified facilities in accordance with the authority delegated by the EPA under Section 111(b) of the Federal CAA. In general, Federal New Source Performance Standards (NSPS) applicable to emission sources at the Deer Creek Station have been incorporated into the State regulations by reference. Federal new source performance standards applicable to emission sources at Deer Creek are reviewed in Section 4.3.

4.2.8 Chapter 74:36:08 – National Emissions Standards for Hazardous Air Pollutants

Chapter 74:36:08 establishes state standards for the emission of hazardous air pollutants (HAPs) from specific emission source categories in accordance with the authority delegated by EPA under Section 112 of the CAA. In general, Federal national emission standards for HAPs applicable to emission sources at the Deer Creek Station have been incorporated into the state regulations by reference. Federal HAP emission standards applicable to emission sources at Deer Cree are reviewed in Section 4.4.

4.2.9 Chapter 74:36:09 – Prevention of Significant Deterioration

Chapter 74:36:09 applies to all areas of the state which are designated attainment or unclassifiable for the NAAQS. Chapter 74:36:09 requires any new major source or major modification to an existing major stationary source located in an attainment or unclassified area to obtain a Prevention of Significant Deterioration (PSD) permit prior to beginning actual construction. In general, the federal PSD regulations in 40 CFR 52.21 have been incorporated into the state regulations by reference.

The proposed Deer Creek Station will be located in Brookings County. Brookings County has been designated as an attainment (or unclassifiable) area for all NAAQS. Therefore, the Deer Creek Station will be subject to the PSD standards if the proposed facility meets the definition of a major stationary source.

A source is considered a major source if it is one of the 28 named PSD source categories listed in Section 169 of the federal Clean Air Act, and has the potential to emit 100 tons per year (tpy) or more of any regulated pollutant. The major source threshold for all other sources (i.e., not included in one of the 28 named source categories) is 250 tpy of any regulated pollutant. Fossil fuel-fired steam electric plants of more than 250 mmBtu/hr heat input are included as one of the 28 named PSD source categories. Although combustion turbines are not included within this source category (as they are not considered steam electric plants), fossil-fuel combustion in the HRSG meets the definition of steam electric plant. Maximum heat input to the Deer Creek duct burners will be greater than 250 mmBtu/hr; therefore, the Deer Creek Station falls into one of the 28 named PSD source categories and will be considered a major source if it has the potential to emit greater than 100 tpy of any regulated pollutant. Based on emission calculations summarized in Section 3, the Deer Creek Station has the potential to emit greater than 100 tpy of NOx and CO. Therefore, the Station meets the definition of a major source.

4. REGULATORY REVIEW

Once a source is considered major, all regulated air pollutants emitted at a rate above the "significant" rate are subject to PSD review. The PSD significant emission rates are included in 40 CFR 52.21(b)(23) a, and are summarized Table 4-4 along with potential emissions from the Deer Creek Station. Based on emission calculations, the Deer Creek Station will be subject to PSD review for CO, NOx, and PM (including PM_{10} and $PM_{2.5}$).

Table 4-4
Comparison of PSD Significant Levels and Expected Annual Emissions

NSR Regulated Pollutants	PSD Significant Level	Deer Creek Station Potential-to-Emit (PTE)	Does PTE Exceed the Significant Level?
	(tpy)	(tpy)	(Yes / No)
Carbon Monoxide	100	256.0	Yes
Nitrogen Oxides	40	119.1	Yes
Sulfur Dioxide	40	11.7	No
PM (total)	25	80.1	Yes
PM_{10} (total)	15	80.1	Yes
$PM_{2.5}$ (total)	10	80.1	Yes
Ozone (VOC)	40	29.7	No
Lead	0.6	3.60×10^{-4}	No
Sulfuric Acid Mist	7	2.21	No

The Federal PSD regulations were recently amended to add $PM_{2.5}$ as a regulated pollutant. On May 16, 2008, U.S.EPA published it final regulations implementing the NSR program for $PM_{2.5}$ (73 FR 28321, May 16, 2008). The final rule included the major source threshold and significant emissions rate for $PM_{2.5}$, as well as offset ratios for $PM_{2.5}$ inter-pollutant trading and applicability of NSR to $PM_{2.5}$ precursors (including SO_2 and NOx). The final rule established a significant emissions level of 10 tpy for direct $PM_{2.5}$ emissions, and a significant emissions level of 40 tpy for SO_2 (as a $PM_{2.5}$ precursor) and NOx (as a $PM_{2.5}$ precursor – if regulated).

The May 16, 2008 rule also describes the process states should follow to implement the new $PM_{2.5}$ NSR rules, and how PM emissions should be permitted during the transition period. States with SIP-approved PSD programs (such as South Dakota) must amend their SIPs to incorporate federal rule changes, and need time to accomplish these SIP amendments. Accordingly, the final rule requires states with SIP-approved PSD programs to submit revised PSD programs for $PM_{2.5}$ by May 2011

4. REGULATORY REVIEW

(within 3-years of publication of the final rule). During the transition period, states may continue to implement a PM_{10} program as a surrogate to meet the PSD program requirements for $PM_{2.5}$.

The PSD regulations require the applicant to control regulated emissions using the Best Available Control Technology (BACT), conduct impact modeling to demonstrate that emissions from the proposed source will not cause or contribute to a violation of the NAAQS or exceed the PSD increment, and comply with the public participation requirements in 74:36:09:03. A complete BACT analysis for NOx, CO, and PM is included in Appendix C, and a summary of the BACT results is included in Section 5.0. As discussed above, for the combustion of natural gas it was assumed that all of the PM emitted would have an aerodynamic diameter less than 2.5 microns (see, e.g., AP-42 Table 1.4-2). Therefore, PM, PM_{10}, and $PM_{2.5}$ emissions from the CT/HRSG are assumed to be the same, and the evaluation of BACT control technologies is applicable to all three categories of PM emissions.

Results of the air quality impact modeling are summarized in Section 7 of this permit application. Detailed impact modeling, including a description of the methodology used to conduct the impact modeling is included in Appendix D. In accordance with the May 16, 2008 NSR implementation rule, PM_{10} emissions were used as a surrogate for $PM_{2.5}$ to demonstrate that emissions from the proposed facility will not exceed the applicable significant impact level (SIL) or PSD increment, and to demonstrate compliance with the PM_{10} and $PM_{2.5}$ NAAQS.

4.2.10 Chapter 74:36:10 – New Source Review

The regulations included in Chapter 74:36:10 apply to areas of the state which are designated as non-attainment pursuant to §107 of the Clean Air Act. As discussed above, the Deer Creek Station will be located in Brookings County, which has been designated as attainment (or unclassifiable) for all NSR regulated pollutants. Therefore, the provisions of Chapter 74:36:10 are not applicable to the Deer Creek Station.

4.2.11 Chapter 74:36:11 – Performance Testing

Section 74:36:11:01 requires all stack performance tests to be made in accordance with the applicable test method specified in 40 CFR §60.17; Part 60 Appendix A; §63.14; Part 63 Appendix A; and Part 51, Appendix M (all July 1, 2005). Section 74:36:11:02 states that the secretary may require a performance test of emissions, including stack sampling, for air pollutants from any source to determine compliance with regulated pollutant emission standards. To ensure compliance with this

4. REGULATORY REVIEW

Chapter, BEPC has proposed compliance tests that will demonstrate compliance with the proposed emission limits and averaging times, and BEPC has proposed to use U.S.EPA approved test methods.

4.2.12 Chapter 74:36:12 – Control of Visible Emissions

Section 74:36:12:01 restricts the discharge into the ambient air from a single unit of emissions any air pollutant of a density equal to or greater than that designated as 20% opacity, as established by U.S. EPA Method 9. Where applicable, BEPC has proposed opacity limits that are in compliance with the requirements of Chapter 74:36:12.

4.2.13 Chapter 74:36:13 – Continuous Emission Monitoring Systems

Section 74:36:13:01 states that the secretary may require major stationary air pollution sources to install, calibrate, operate, and maintain equipment approved by the department for the continuous monitoring and recording of emission data to determine compliance with a regulated air pollutant standard. BEPC has proposed continuous emissions monitoring systems (CEMS) to measure NOx and CO emissions from the CT/HRSG.

4.2.14 Chapter 74:36:14 – Variances (Repealed, 23 SDR 106, effective December 29, 1996)

4.2.15 Chapter 74:36:15 – Open Burning

Air pollution control regulations in Chapter 74:36:15 have been transferred to other sections or have been repealed, and will impose no additional limitations on the Deer Creek facility.

4.2.16 Chapter 74:36:16 – Acid Rain Program

In general, Chapter 74:36:16 incorporates the Federal Acid Rain Program into the state regulations by reference. Pursuant to Title IV of the 1990 CAA Amendments, U.S.EPA established a program to control pollution emissions that contribute to the formation of acid rain. The acid rain regulations, codified under 40 CFR Parts 72, 75 and 76 are applicable to “affected units” as defined in the regulations. A summary of the applicable Acid Rain Program regulations is provided in Section 4.5.

4.2.17 Chapter 74:36:17 – Rapid City Street Sanding and Deicing

The provisions of Chapter 74:36:17 are not applicable to the Deer Creek Station.

4.2.18 Chapter 74:36:18 – Regulations for State Facilities in the Rapid City Area

The provisions of Chapter 74:36:18 are not applicable to the Deer Creek Station.

4.2.19 Chapter 74:36:19 – Mercury Budget Trading Program

In general, Chapter 74:36:19 incorporated, by reference, the federal mercury budget trading program. The federal mercury budget trading program was applicable to coal-fired boilers serving a generator with a nameplate capacity greater than 25 MW producing electricity for sale (40 CFR 4104(a)). Subsequently, the U.S. Court of Appeals for the District of Columbia Circuit vacated the federal mercury budget trading program. Therefore, the provisions of Chapter 74:36:19 are not applicable to the Deer Creek Station.

4.3 New Source Performance Standards (NSPS)

The U.S.EPA has established NSPS for many kinds of industrial facilities and processes. As described above, federal NSPS standards have been incorporated into Chapter 74:36:07 of the South Dakota Air Pollution Control Program. NSPS regulations that may be applicable to the Deer Creek Station include:

40 CFR Part 60 Subpart A	General Provisions
40 CFR Part 60 Subpart KKKK	Stationary Combustion Turbines
40 CFR Part 60 Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The applicable NSPS requirements are summarized below:

4.3.1 40 CFR Part 60 Subpart A: General Provisions

The general provisions included in Subpart A are applicable to any source subject to a source-specific NSPS. Unless specifically excluded by the source-specific NSPS, Subpart A requires, among other things: (1) notification of the date construction is commenced; (2) notification of the actual date of initial startup; (3) initial performance tests within specified time frames; (4) notification of any performance test dates; (5) general monitoring requirements; and (6) general record keeping requirements. As described in subsection 4.3.2, the Deer Creek CT/HRSG will be subject to the combustion turbine NSPS; therefore, the facility will be subject to the Subpart A general provisions summarized above.

4.3.2 40 CFR Part 60 Subpart KKKK: Combustion Turbines

On July 6, 2006, U.S.EPA published a final rule promulgating standards of performance for new stationary gas turbines in 40 CFR part 60, subpart KKKK. The updated standards reflect changes in the NOx emission control technologies and turbine design since standards for these units were originally promulgated in 40 CFR part 60, subpart GG. The subpart KKKK standards of performance (40 CFR §§60.4300 to 60.4420, inclusive) have been incorporated into South Dakota air quality regulations at Chapter 74:36:07:89.

The subpart KKKK NSPS applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ (10 mmBtu) per hour that commence construction, modification, or reconstruction after February 18, 2005. A stationary combustion turbine is defined as all equipment, including but not limited to the combustion turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, and regenerative/recuperative cycle stationary combustion turbine, any combined-cycle combustion turbine, and any combined heat and power combustion turbine based system.

The applicability in subpart KKKK is similar to that of 40 CFR Part 60, subpart GG, except that the subpart KKKK rules apply to new, modified, and reconstructed stationary combustion turbines, and their associated heat recovery steam generators (HRSG) and duct burners. The stationary combustion turbines subject to subpart KKKK are exempt from the requirements of NSPS requirements in 40 CFR Part 60, subpart GG. Heat recovery steam generators and duct burners subject to subpart KKKK are exempt from the NSPS requirements of 40 CFR Part 60, subparts Da, Db, and Dc (applicable to boilers).

Subpart KKKK includes emission standards for NOx and SO_2. The applicable subpart KKKK emission standards are summarized in Table 4-5.

4. REGULATORY REVIEW

Table 4-5
40 CFR Part 60 Subpart KKKK New Source Performance Standards

Pollutant	Standard	Compliance Monitoring
NO_x	New, modified, or reconstructed turbine firing natural gas with a combustion turbine heat input at peak load >850 mmBtu/hr (HHV)	15 ppm @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh)
SO_2		110 ng/J (0.90 lb/MWh gross output), or must not burn any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/mmBtu) heat input

Based on emission calculations summarized in Section 3.0, NOx and SO_2 emissions from the Deer Creek CT/HRSG will meet the applicable subpart KKKK NSPS requirements. In addition, to the NSPS emission standards, subpart KKKK requires initial performance tests be conducted to demonstrate compliance with the emission standards, as well as emissions monitoring, record keeping and reporting requirements.

4.3.3 40 CFR Part 60 Subpart IIII: Stationary Compression Ignition Internal Combustion Engines

On July 11, 2006, U.S.EPA published new source performance standards for stationary compression ignition (CI) internal combustion engines (ICE) (71 FR 39154). The CI ICE NSPS standards of performance (40 CFR Part 60 subpart IIII) have been incorporated into South Dakota air quality regulations at Chapter 74:36:07:88. The CI ICE NSPS limits emissions of NO_x, PM, SO_2, CO, and hydrocarbons (HC) from stationary diesel internal combustion engines. Provisions of the CI ICE NSPS apply to manufacturers, owners, and operators of stationary CI internal combustion engines. In general, BEPC will be required to purchase engines certified by the manufacturer to meet the applicable emissions levels.

CI engines include internal combustion engines that are not spark ignition engines, including diesel engines. Both the emergency diesel generator and fire-water pump proposed for the Deer Creek Station are classified as stationary CI engines subject to the provisions of the CI ICE NSPS. Emissions standards established in the rule depend on the engine’s horsepower class and mode of operation (e.g., continuous operation or emergency operation). Specific definitions applicable to the Deer Creek diesel engines include “emergency stationary internal combustion engine” and “fire pump engine”. The Deer Creek emergency diesel generator and fire water pump are both classified as

4. REGULATORY REVIEW

emergency stationary internal combustion engines, and the fire water pump meets the definition of a fire pump engine.

The NSPS includes emission standards for model year 2007 and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kW (3,000 hp) and a displacement of less than 10 liters per cylinder that are not fire pump engines (40 CFR 60.4202). The emergency diesel generator engine proposed for the Deer Creek Station falls into this classification of engines. The rule requires that emergency stationary CI ICE meet the Tier 2 through Tier 3 nonroad CI engine emission standards, and Tier 4 nonroad CI engine standards that do not require add-on control, according to the nonroad diesel engine schedule in 40 CFR 89.112 and 40 CFR 89.113.

Fire pump engines are subject to the final rule beginning with the first model year that new fire pump engines in a particular horsepower class must meet standards more stringent than Tier 1 standards, which can be any model year from 2008 to 2011, depending on the horsepower of the engine (40 CFR 60.4202(d)).

Based on a review of the subpart IIII standards and the nonroad CI diesel engine emission standards, the applicable CI ICE NSPS emission standards are summarized below:

Emergency Stationary CI ICE (40 CFR 60.4202(a)): Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power ≤ 2,237 kW (3,000 hp) and a displacement of less than 10 liters per cylinder, that are not fire pump engines, to the emission standards specified in Table 4-6.

Table 4-6
CI ICE NSPS Emission Standards - Emergency Diesel Generators

kW > 560	**NOx**	**HC**	**NMHC +NOx**	**CO**	**PM**
	gpkW-hr (g/HP-h)	**gpkW-hr (g/HP-h)**	**gpkW-hr (g/HP-h)**	**gpkW-hr (g/HP-h)**	**gpkW-hr (g/HP-h)**
Tier 1 Model Year 2000	9.2 (6.86)	1.3 (0.97)	--- (---)	11.4 (8.50)	0.54 (0.40)
Tier 2 Model Year 2006	--- (---)	--- (---)	6.4 **(4.77)**	3.5 **(2.61)**	0.20 **(0.15)**

Source: 40 CFR 89.112 and 89.113. Emission standards included in the regulation (g/kW-hr) were converted to g/HP-hr.

4. REGULATORY REVIEW

<u>Stationary Fire Pump Engines (40 CFR 60.4202(d))</u>: Fire pump engines are subject to the final rule beginning with the first model year that new fire pump engines in a particular horsepower class must meet standards more stringent than Tier 1 standards, which can be any model year from 2008 to 2011, depending on the horsepower of the engine. A summary of the applicable emission standards is provided in Table 4-7

Table 4-7
CI ICE NSPS Emission Standards - Fire Water Pump Engines

Maximum Engine Power	Model Year	NMHC +NOx	CO	PM
		g/kW-h g/HP-h	g/kW-h g/HP-h	g/kW-h g/HP-h
175 ≤ HP < 300	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ (Note 1)	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
300 ≤ HP < 600	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ (Note 1)	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)

Source: Table 4 to Subpart IIII of Part 60 – Emission Standards for Stationary Fire Pump Engines.
Note: In model years 2009–11, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

To ensure compliance with the applicable CI ICE NSPS emission standards, BEPC will be required to purchase engines certified by the manufacturer to meet the applicable emissions levels.

4.4 National Emission Standards for Hazardous Air Pollutants (NESHAPS)

Section 112 of the CAA requires EPA to list categories and subcategories of major sources of hazardous air pollutants (HAPs), and to establish national emission standards for hazardous air pollutants (NESHAPs) for each source category. The NESHAP regulations, codified under 40 CFR Parts 61 and 63 and incorporated in to the South Dakota Air Pollution Control Program at Chapter 74:36:08, are designed to regulate specific categories of stationary sources with the potential to emit one or more hazardous air pollutant.

Applicability of the rules regulating HAP emissions from source categories are limited to emission sources located at major source of HAP emissions. A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tpy or more, or any combination of HAP at a rate of 25 tpy or more.

4. REGULATORY REVIEW

Based on emission calculations summarized in section 3.5 (and detailed in Appendix C), potential HAP emissions from all sources at the Deer Creek Station will be less than 25 tpy (7.67 tpy, see Table 3-18). Formaldehyde is the individual HAP constituent that will be emitted in the greatest quantity. Based on emission calculations, potential formaldehyde emissions from all emission sources will be 4.51 tpy (see, Table 3-16, and Appendix B). Because the facility does not have the potential to emit any single HAP at a rate greater than 10 tpy, or any combination of HAP at a rate of 25 tpy or more, the Deer Creek Station does not meet the definition of a major source of HAP emissions. Therefore, potentially applicable NESHAP standards do not apply to emission sources at the Deer Creek Station.

4.5 Acid Rain Program

Pursuant to Title IV of the 1990 CAA Amendments, U.S.EPA established a program to control pollution emissions that contribute to the formation of acid rain. The Federal Acid Rain Program has been incorporated into the South Dakota Air Pollution Control Program at Chapter 75:36:16. The acid rain regulations, codified under 40 CFR Parts 72, 75 and 76 are applicable to "affected units" as defined in the regulations. As a "new utility unit," the Deer Creek CT/HRSG meets the definition of an affected unit under 40 CFR 72.6(a)(3), and is therefore subject to the Acid Rain Program.

Owners or operators of an affected unit are subject to the following Acid Rain Program requirements:

- Acid Rain Permit Application;
- SO_2 emission allowances;
- NOx emission limitations;
- Acid Rain Compliance Plan; and
- Emission monitoring requirements.

For new units, an Acid Rain Permit application must be submitted at least 24 months before the date of initial operation of the unit. The application must demonstrate compliance with the Acid Rain Program requirements and include a complete compliance and monitoring plan.

4.6 Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) Rule (40 CFR Part 64) applies to pollutant-specific emissions units meeting the following criteria:

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

Compliance assurance monitoring is applicable to permit applications received on or after April 20, 1998, from major sources applying for a Title V air quality permit. The CAM rule does not apply to emission units or pollutants subject to a Section 111 NSPS or Section 112 NESHAP issued after November 15, 1990, the Acid Rain Program, or emissions trading programs. In addition, the CAM rules do not apply to inherent process equipment that does not meet the definition of an emission control device under the rule.

Emissions from sources at the Deer Creek Station, including the CT/HRSG, emergency diesel generator, and fire-water pump are subject an NSPS, NESHAP, or the Acid Rain Program monitoring requirements, and therefore exempt from the CAM standards. Therefore, the Deer Creek Station is not required to conduct a compliance assurance monitoring review or implement a CAM plan for these sources. CAM applicability for emission sources at the facility will be re-evaluated, and a CAM plan meeting the requirements of 40 CFR Part 64 will be developed for submittal (if needed) with the facility’s Title V operating permit application.

5. BEST AVAILABLE CONTROL TECHNOLOGY

5.0 Introduction

The Deer Creek Station will be classified as a new major source of emissions. Deer Creek emission sources are subject to BACT review for each pollutant emitted in quantities greater than the significant level defined in 40 CFR 52.21(b)(23) (see, Table 4-4). Based on potential-to-emit emission calculations summarized in Section 3.0, the Deer Creek Station is subject to BACT review for the following NSR-PSD pollutants:

- Nitrogen Oxides (NO_x)
- Carbon Monoxide (CO)
- Particulate Matter (including PM, PM_{10} and $PM_{2.5}$)

Based on emission calculations, SO_2, VOC, sulfuric acid mist, and lead emissions from the Deer Creek Station will be below the applicable PSD significant levels. Therefore, emissions of these PSD pollutants are not subject to BACT review. Other pollutants for which PSD significance levels are established, including fluorides, asbestos, vinyl chloride, H_2S, and total reduced sulfur (TRS) are not expected to be emitted from sources at Deer Creek.

This section summarizes the results of the Deer Creek Station BACT analysis, including the proposed emission controls and emission limits. The complete BACT analysis is included in Appendix C.

5.1 Definition of BACT

The requirements to conduct a BACT analysis are set forth in Chapter 74:36:09 of the South Air Pollution Control Program, and 40 CFR 52.21. BACT is defined in 40 CFR 52.21(b)(12) as:

> …an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the CAA] which would be emitted from any proposed major stationary source or major modification which the [secretary], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…."

According to U.S.EPA policy, BACT should be determined using the "top-down" approach, whereby the applicant is responsible for identifying and ranking, according to control effectiveness, all technically feasible control options for each pollutant subject to BACT. If it can be shown that the most stringent alternative is unrepresentative of BACT based on energy, environmental, or economic impacts, this alternative may be rejected and the next most stringent alternative is considered. This process continues until the alternative under consideration cannot be rejected by any substantial or unique technical, economic, energy or adverse environmental objection.

5.2 Summary of CT/HRSG BACT Analysis

Based on the detailed BACT analysis included in Appendix C of this permit application, a combination of combustion controls and post-combustion emission control systems is being proposed as BACT for the Deer Creek CT/HRSG. BEPC is proposing selective catalytic reduction (SCR) in combination with low-NOx combustion controls as BACT for NOx control, and a controlled NOx emission limit of 3.5 ppmvd @ 15% O_2 (30-day rolling average). A controlled NO_x emission rate of 3.5 ppmvd @ 15% O_2 (30-day average) represents the most aggressive NOx emission rate achievable on an on-going long-term basis without significant collateral environmental impacts associated with SCR control. SCR has been approved as BACT for natural gas-fired combined cycle units, and an emission rate of 3.5 ppmvd @ 15% O_2 is consistent with the BACT emission limit established for other similarly sized combined cycle units.

Combustion controls represent BACT for CO control. BEPC is proposing to meet a CO BACT emission limit of 9.0 ppmvd without duct firing and 18.3 ppmvd when duct firing (30-day rolling average). CO emissions will be somewhat higher when duct firing due to the higher CO emission rate associated with the duct burners. Post-combustion CO controls were determined not to be economically feasible for the Deer Creek Station. Based on the BACT economic impact analysis (Appendix C, Section 4.4.1), the average annual cost effectiveness of an oxidation catalyst control system was calculate to be $3,324/ton. Equipment costs, energy costs, and annual operating costs (e.g., routine catalyst replacement) all have a significant impact on the cost of an oxidation catalyst control system. Total annual costs associated with the oxidation catalyst system, including capital recovery and annual O&M, are estimated to be in the range of $479,300/year. The cost effectiveness of an oxidation catalyst system at the Deer Creek Station is significant, and should preclude the control system from consideration as BACT.

BEPC is proposing natural gas-firing and combustion controls as BACT for PM (including PM10 and PM2.5). Based on information available from combustion turbine and duct burner vendors, BEPC is proposing a total PM BACT emission limit of 0.011 lb/mmBtu (18.6 lb/hr without duct firing and 23.2 lb/hr when duct firing). This emission rate includes both filterable and condensible PM emissions. No potentially feasible and applicable post-combustion PM control systems were identified.

The proposed CT/HRSG BACT emission limits and control technologies are summarized in Table 5-1.

5. BEST AVAILABLE CONTROL TECHNOLOGY

Table 5-1
Proposed Main Boiler BACT Emission Limits and Control Technologies*

Pollutant	Proposed BACT Limit (30-day rolling average)	Proposed BACT Technology	Compliance Demonstration Methodology
NOx	3.5 ppmvd @ 15% O2	Low-NOx combustion controls and SCR	NOx CEMs
CO	9.0 ppmvd (when not duct firing) 18.2 ppmvd (when duct firing)	combustion controls	CO CEMs
PM (PM10 and PM2.5)	0.011 lb/mmBtu	natural gas fuel and good combustion practices	Stack Test U.S.EPA Test Method 201a/202

*BACT emission limits summarized in Table 5-1 will apply at all times during normal CT/HRSG operation, excluding periods of startup and shutdown. BEPC has prepared CT startup emission calculations, and has proposed alternative emission limits applicable during startup/shutdown.

5.3 Summary of Emergency Generator and Fire-Water Pump BACT Analysis

BEPC is proposing low sulfur diesel fuel, combustion controls, and limited annual hours of operation as BACT for the emergency diesel generator and fire water pump. BEPC will meet the applicable compression ignition internal combustion engine (CI ICE) NSPS emission standards. The recently published NSPS standards were based on the best demonstrated system of continuous emission reduction, considering costs, non-air quality health, and environmental and energy impacts. Commercial availability of post-combustion control technologies is limited, and post-combustion control systems are not economically feasible on emergency stationary CI engines.

Results of the BEPC emergency generator and fire-water pump BACT analyses are summarized in Tables 5-2 and 5-3, respectively. The complete BACT analyses are included in Appendix C of this permit application.

Table 5-2
Proposed Emergency Generator BACT Emission Limits and Control Technologies

]Pollutant	Proposed Emission Limit	Basis
NMHC + NO_x (EDG)	4.77 g/hp-hr	CI ICE NSPS and limited annual hours of operation.
CO (EDG)	2.61 g/hp-hr	CI ICE NSPS and limited annual hours of operation.
PM_{10} filterable (EDG)	0.15 g/hp-hr	CI ICE NSPS and limited annual hours of operation.

5. BEST AVAILABLE CONTROL TECHNOLOGY

Table 5-3
Proposed Fire-Water Pump BACT Emission Limits and Control Technologies

Pollutant	Proposed Emission Limit	Basis
NMHC + NO_x (FWP)	3.0 g/hp-hr	CI ICE NSPS and limited annual hours of operation.
CO (FWP)	2.6 g/hp-hr	CI ICE NSPS and limited annual hours of operation.
PM_{10} filterable (FWP)	0.15 g/hp-hr	CI ICE NSPS and limited annual hours of operation.

5.4 Summary of the Emergency Inlet Air Heater BACT Analysis

BEPC is proposing a combination of fuel characteristics, combustion controls, and limited annual hours of operation as BACT for the emergency inlet air heater. NOx emissions from the inlet air heater will be controlled using combustion controls to meet a NOx BACT limit of 0.05 lb/mmBtu (approximately 50 lb/mmscf). An emission rate of 0.05 lb/mmBtu is consistent with the BACT emission rates for other recently permitted and similarly sized natural gas-fired heaters. Post-combustion emission control systems are not commercially available and would have limited application on a small natural gas-fired process heater that will be fired a limited number of hours per year.

BEPC is proposing combustion controls and limited hours of operation as BACT for CO control, and a CO emission rate of 0.08 lb/mmBtu (approximately 84 lb/mmscf). It is expected that the proposed inlet air heater, equipped with combustion controls, will achieve average CO emission rates below 0.08 lb/mmBtu under all normal operating conditions (including low load operation but excluding periods of startup, shutdown, and malfunction), while maintaining NOx control.

PM emissions from the inlet air heater will be limited based on the low ash content of natural gas. Based on AP-42 emission factors for natural gas combustion, BEPC is proposing a PM BACT emission rate of 7.6 lb/mmscf (0.0075 lb/mmBtu).

Results of the BEPC emergency inlet air heater BACT analysis are summarized in Table 5-4. The complete BACT analysis is included in Appendix C of this permit application.

5. BEST AVAILABLE CONTROL TECHNOLOGY

Table 5-4
Proposed Emergency Inlet Air Heater BACT Emission Limits and Control Technologies

Pollutant	Proposed Emission Limit	Proposed BACT Technology
NO_x (Inlet Air Heater)	0.05 lb/mmBtu	Combustion Controls
CO (Inlet Air Heater)	008 lb/mmBtu	Combustion Controls
PM_{10} total (Inlet Air Heater)	0.0075 lb/mmBtu	Natural Gas and Good Combustion Practices

6. MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

6.0 Introduction

Section 112 of the CAA requires EPA to list categories and subcategories of major sources of hazardous air pollutants (HAPs), and to establish national emission standards for hazardous air pollutants (NESHAPs) for each source category. The NESHAP regulations (codified under 40 CFR Parts 61 and 63 and incorporated in to the South Dakota Air Pollution Control Program at Chapter 74:36:08) are designed to regulate specific categories of stationary sources with the potential to emit one or more hazardous air pollutant.

Applicability of the rules regulating HAP emissions from source categories are limited to emission sources located at major source of HAP emissions. A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tpy or more, or any combination of HAP at a rate of 25 tpy or more.

6.1 Applicable MACT Standards

Based on emission calculations provide in Appendix C and summarized in section 3.5, potential HAP emissions from all sources at the Deer Creek Station will be less than 25 tpy (7.62 tpy, see Table 3-18). Formaldehyde is the individual HAP constituent that will be emitted in the greatest quantity. Based on emission calculations, potential formaldehyde emissions from all emission sources will be 4.51 typ (see, Table 3-16, and Appendix B). Because the facility does not have the potential to emit any single HAP at a rate greater than 10 tpy, or any combination of HAP at a rate of 25 tpy or more, the Deer Creek Station does not meet the definition of a major source of HAP emissions. Therefore, potentially applicable NESHAP standards do not apply to emission sources at the Deer Creek Station.

7. CLASS II AIR QUALITY IMPACT ANALYSIS

7.0 Class II Air Quality Impact Analysis - Summary

A construction permit application for a new PSD source must include a comprehensive air quality impact evaluation. Chapter 74:36:09 requires the owner/operator of a proposed major source to demonstrate that, as of the source's start-up date, allowable emissions from the source would not cause or contribute to any increase in ambient concentrations that would exceed: (1) any NAAQS in any air quality control region; or (2) the remaining available PSD increment for the specified air contaminants. U.S.EPA has established NAAQS and PSD increments for Class I and Class II areas (see, Tables 4-1, 4-2, and 4-3). Class II areas include all areas designated as attainment or unclassifiable which are not established as Class I areas under §162(a) of the federal CAA. All areas surrounding the proposed facility are subject to the Class II PSD increment requirements. Class II impact modeling is required for each PSD pollutant that will be emitted at a rate above the significant emission rate listed in 40 CFR 52.21. Based on emission calculations provided in Section 3.0 (and summarized in Table 3-15), Class II ambient air quality impact modeling was conducted to evaluate potential impacts on the applicable NO_x, CO, and PM_{10} NAAQS and PSD increments.

BEPC conducted air quality impact modeling in accordance with guidance provided by U.S.EPA in Appendix W to Part 51 (Guideline on Air Quality Models). Potential ambient air quality impacts were evaluated using potential-to-emit emissions calculated using permit emission limits and applicable source design parameters. Estimates of ambient concentration impacts were based on the applicable air quality models specified by U.S.EPA and approved by DENR. BEPC submitted a Class II Air Dispersion Modeling Protocol to DENR for the Deer Creek project in October 2008.

In the Class II Air Dispersion Modeling Protocol, BEPC proposed using the AERMOD program (version 07026) for refined air quality modeling. The U.S.EPA BPIPPRM program (version 04274) was used to prepare building dimensions for input to the AERMOD program, and to help estimate GEP stack height. Air quality modeling software used was obtained from the U.S.EPA Support Center for Regulatory Atmospheric Modeling (SCRAM). Modeling was performed using regulatory default options that include the following: stack tip downwash, incorporating the effects of elevated terrain, calms processing routine, and missing data processing routine. The methodology proposed for air quality modeling was designed for the purpose of verifying that the Deer Creek Station will not cause or contribute to impacts on ambient air quality that exceed the applicable NAAQS or PSD Increments.

Modeling of potential ambient air quality impacts associated with the Deer Creek project was conducted in two steps, as follows.

7. CLASS II AIR QUALITY IMPACT ANALYSIS

(1) First, via refined modeling the significant impact area of emissions from the project will be determined for all applicable pollutants and averaging times. The impact of emissions from the project alone was compared to the Significant Impact Levels (SILs), the NAAQS, and the PSD Increments.

(2) Second, if any pollutants for which emissions from the project alone would have been predicted to have significant impacts, significant impact radii would have been defined and reported. A multi-source analysis would then be performed, incorporating a regional source emission inventory as supplied by the DENR. That regional source inventory would include existing sources and permitted PSD sources that have not yet begun operation. PSD or "new" sources would include all sources that have consumed PSD Increment in the vicinity of the proposed source since the PSD baseline date, or will consume PSD Increment in the future after they begin operation. Predictions of air quality impacts for PSD pollutants due to emissions from the new source inventory would be compared to the PSD Increments to demonstrate compliance. Predictions of air quality impacts for NAAQS criteria pollutants due to emissions from the inventory of all sources including existing and new, would be summed with background ambient air quality levels (provided by the DENR), and compared to the NAAQS to demonstrate compliance.

The air dispersion modeling analysis has been included in this Permit Application as Appendix D. The results of the analysis that ambient air quality impacts from the project will not exceed the PSD SILs, NAAQS, or PSD Increment. Therefore, the Deer Creek project will not cause or contribute to adverse ambient air quality impacts.

8. ADDITIONAL IMPACT ASSESSMENT

8.0 Additional Impact Assessment

The PSD regulations (40 CFR 51.166) require an analysis of potential secondary impacts resulting from growth associated with a proposed PSD project. The growth analysis requires an assessment of the projected air quality impacts and impairment to visibility, soils, and vegetation as a result of the new source and general commercial, residential, industrial, and other growth associated with the source. This section includes an assessment of potential Class II visibility impacts, and an assessment of potential impacts to soils and vegetation as a result of Deer Creek Station and general commercial, residential, and industrial growth associated with the Deer Creek project.

8.1 Class II Visibility Analysis

The Clean Air Act amendments of 1977 require additional evaluation of new emission sources to determine potential impacts on visibility. A Level-1 visibility impact screening was conducted using the U.S.EPA VISCREEN model (version 88341). The screening followed guidance provided U.S.EPA's document "Workbook for Plume Visual Impact Screening and Analysis (Revised)". The analysis was performed for the Pipestone National Monument (PNM) in southwestern Minnesota. PNM is located approximately 45 km south-southeast of the proposed facility.

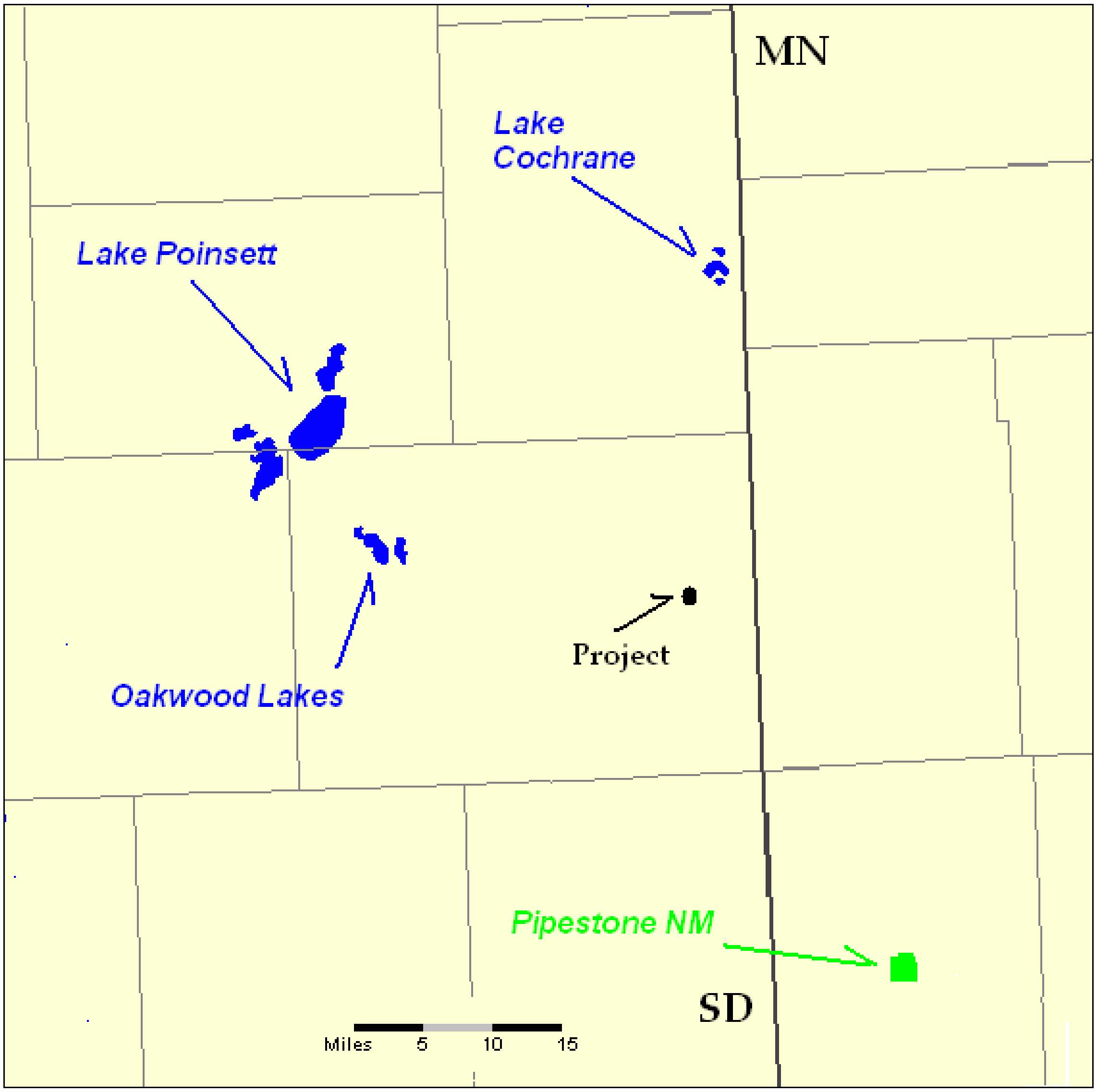
Per discussion with DENR, visibility analyses were also performed for South Dakota state parks within 50 km of the facility. Visibility analyses were performed for the following state parks:

- Lake Cochrane, SD (35 km north of project)
- Lake Poinsett, SD (47 km northwest of project)
- Oakwood Lakes, SD (34 km west of project)

A map showing PNM, the state parks, and the proposed facility is provided in Figure 8-1.

8. ADDITIONAL IMPACT ASSESSMENT

Figure 8-1
Project Site, State Parks and the Pipestone National Monument.



The VISCREEN model requires a single NOx emission rate (input into the model as an NO_2 equivalent) and a single PM emission rate. Following U.S.EPA's guidance, PM and NO_2 emission rates used in VISCREEN should represent short-term rates.

8. ADDITIONAL IMPACT ASSESSMENT

The PM emission rate input into VISCREEN (24.55 lb/hr) is the sum of the maximum total (condensable plus filterable) PM emission rates from the CT/HRSG (23.2 lb/hr; see Appendix D, Table 7); emergency inlet air heater (0.19 lb/hr; see Appendix D, Table 9); emergency generator (0.97 lb/hr; see Appendix D, Table 10); and fire water pump (0.19 lb/hr; see Appendix D, Table 10).

Per discussion with DENR, a conservative NO_2 / NO_x ratio of 1.0 was assumed (see Appendix D, Section 5.7.1). The NO_x emission rate input into VISCREEN (99.24 lb/hr) is the sum of the maximum hourly NO_x emission rate from the CT/HRSG (65.5 lb/hr during cold start-up; see Appendix D, Table 8); emergency inlet air heater (2.45 lb/hr; see Appendix D, Table 9); emergency generator (28.9 lb/hr; see Appendix D, Table 10); and fire water pump (2.39 lb/hr; see Appendix D, Table 10). The PM and NOx emission rates used in VISCREEN are summarized in Table 8-1.

Table 8-1
VISCREEN Input Emission Rates

=Pollutant	Input emission rate (lb/hr)	Notes
PM	24.55	Sum of maximum hourly total PM emission rate from the CT/HRSG, air inlet heater, emergency generator and fire water pump.
NO_2	99.24	Sum of maximum hourly total NO_x emission rate from the CT/HRSG, air inlet heater, emergency generator and fire water pump. Assumes a NO_2 / NO_x ratio of 1.0.

VISCREEN requires background visible range and course-receptor distances. Per U.S.EPA guidance the background visible range was set to 40 km. VISCREEN also requires source-observer distances and maximum/minimum receptor distances. These distances were determined following EPA guidance. These distances are listed in Table 8-2.

Table 8-2
VISCREEN Source-Receptor Distances

Receptor	Source-Observer Distance (km)	Minimum Source-Observer Distance (km)	Maximum Source-Observer Distance (km)
Pipestone NM	44	44	46
Lake Cochrane	34	34	38
Lake Poinsett	45	45	59
Oakwood Lakes	34	34	41

8. ADDITIONAL IMPACT ASSESSMENT

8.1.1 Class II Visibility Analysis - Results

VISCREEN describes views in terms of the scattering angle (theta), azimuth and distance from the observer to receptor. There are currently no color difference parameter (delta-E) and no contrast thresholds for Class II areas and state parks. However, for Class I areas, the predicted delta-E threshold is 2.0 and the predicted contrast threshold is 0.05.

Results from VISCREEN for PNM, Lake Cochrane, Lake Poinsett and Oakwood Lakes are listed in Tables 8-3 through 8-6 respectively. Results for PNM in Table 8-3 show that the maximum predicted delta-E (1.036 inside view; 1.073 outside view) and the maximum contrast thresholds at PNM (0.005 inside; 0.006 outside) do not exceed Class I thresholds. Modeling results for Lake Cochrane, Lake Poinsett and Oakwood Lakes (Tables 8-4 through 8-6) also show that the maximum delta-E and contrast do not exceed Class I thresholds at any of the analyzed state parks.

Table 8-3
VISCREEN Results for Pipestone National Monument (PNM)

Maximum Visual Impacts Inside Pipestone National Monument					
Background	Theta (deg.)	Azimuth (deg.)	Distance (km)	Predicted Delta-E	Predicted Contrast
Sky	10	84	44.0	1.036	0.003
Sky	140	84	44.0	0.369	-0.007
Terrain	10	84	44.0	0.363	0.005
Terrain	140	84	44.0	0.082	0.003
Maximum Visual Impacts Outside Pipestone National Monument					
Background	Theta (deg.)	Azimuth (deg.)	Distance (km)	Predicted Delta-E	Predicted Contrast
Sky	10	55	39.4	1.073	0.003
Sky	140	55	39.4	0.374	-0.007
Terrain	10	0	1.0	0.613	0.006
Terrain	140	0	1.0	0.182	0.006

8. ADDITIONAL IMPACT ASSESSMENT

Table 8-4
VISCREEN Results for Lake Cochrane

Maximum Visual Impacts Inside Lake Cochrane					
Background	Theta (deg.)	Azimuth (deg.)	Distance (km)	Predicted Delta-E	Predicted Contrast
Sky	10	84.	34.0	1.442	0.003
Sky	140	84.	34.0	0.538	-0.009
Terrain	10	84.	34.0	0.633	0.008
Terrain	140	84.	34.0	0.141	0.005
Maximum Visual Impacts Outside Lake Cochrane					
Background	Theta (deg.)	Azimuth (deg.)	Distance (km)	Predicted Delta-E	Predicted Contrast
Sky	10	35.	27.0	1.538	0.004
Sky	140	35.	27.0	0.538	-0.011
Terrain	10	0.	1.0	1.473	0.015
Terrain	140	0.	1.0	0.428	0.015

Table 8-5
VISCREEN Results for Lake Poinsett

Maximum Visual Impacts Inside Lake Poinsett					
Background	Theta (deg.)	Azimuth (deg.)	Distance (km)	Predicted Delta-E	Predicted Contrast
Sky	10.	84.	45.0	0.983	0.002
Sky	140.	84.	45.0	0.348	-0.007
Terrain	10.	84.	45.0	0.338	0.005
Terrain	140.	84.	45.0	0.077	0.003
Maximum Visual Impacts Outside Lake Poinsett					
Background	Theta (deg.)	Azimuth (deg.)	Distance (km)	Predicted Delta-E	Predicted Contrast
Sky	10.	60.	41.2	1.040	0.003
Sky	140.	60.	41.2	0.364	-0.007
Terrain	10.	0.	1.0	0.562	0.005
Terrain	140.	0.	1.0	0.167	0.005

8. ADDITIONAL IMPACT ASSESSMENT

Table 8-6
VISCREEN Results for Oakwood Lakes

Maximum Visual Impacts Inside Oakwood Lakes					
Background	Theta (deg.)	Azimuth (deg.)	Distance (km)	Predicted Delta-E	Predicted Contrast
Sky	10.	84.	34.0	1.442	0.003
Sky	140.	84.	34.0	0.538	-0.009
Terrain	10.	84.	34.0	0.633	0.008
Terrain	140.	84.	34.0	0.141	0.005
Maximum Visual Impacts Outside Oakwood Lakes					
Background	Theta (deg.)	Azimuth (deg.)	Distance (km)	Predicted Delta-E	Predicted Contrast
Sky	10.	35.	27.0	1.538	0.004
Sky	140.	35.	27.0	0.538	-0.011
Terrain	10.	0.	1.0	1.473	0.015
Terrain	140.	0.	1.0	0.428	0.015

8.1.2 VISCREEN Input and Output Files

Specifications of the VISCREEN input and output files are listed in Table 8-7 for reference.

Table 8-7
VISCREEN Input and Output Files

File contents	**File name**
Input file with parameters for PNM	Pipeston.inp
Output file with results for PNM	Pipeston.out
Input file with parameters for Lake Cochrane State Park	Lcochran.inp
Output file with parameters for Lake Cochrane State Park	Lcochran.out
Input file with parameters for Lake Poinsett State Park	Lpoinset.inp
Output file with parameters for Lake Poinsett State Park	Lpoinset.out
Input file with parameters for Oakwood Lake State Park	Oakwoodl.inp
Output file with parameters for Oakwood Lake State Park	Oakwoodl.out

8. ADDITIONAL IMPACT ASSESSMENT

8.2 Growth Analysis

A growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the proposed facility and to estimate secondary emissions resulting from that associated growth. Associated growth includes residential and commercial/industrial growth projected as a result of the proposed project. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. While secondary activities are not directly related to operating the proposed project, the growth analysis identifies and evaluates emissions from secondary activities that can reasonably be expected to occur. A growth analysis was prepared for the Deer Creek Project, including:

- review of the current population and land use in the area;
- estimated project-related industrial, commercial, and residential growth in the area;
- estimated air emissions generated by permanent project-related growth; and
- qualitative air quality impact assessment associated with projected growth related emission.

The proposed Deer Creek Station will be located in Brookings County, South Dakota. The project site is located in a rural area in South Dakota. White, South Dakota (population 530) is the nearest town, located approximately six miles northwest of the project site. Nearby major population centers include Brookings, Watertown and Sioux Falls. Brookings is located approximately 12 miles southwest of the project site, Watertown is located approximately 45 miles northwest of the project site, and Sioux Falls is located approximately 50 miles southwest of the project.

The Deer Creek Station is expected to increase employment in the area. During construction, which is projected to last approximately 2 years, the project is expected to employ as many as 430 workers. Following the construction phase, projected employment, reflecting full-time jobs directly tied to the operation of Deer Creek, is estimated at 25 to 30.

Although qualified craft workers (e.g., electricians, pipe fitters, welders, etc.) may be available from the Brookings, Watertown, and Sioux Falls areas, the availability of craft workers in the immediate area may be limited. Therefore, some of the skilled workers needed during the construction phase are expected to temporarily relocate from major metropolitan areas in the central U.S., including Minneapolis, Minnesota (located within about 170 miles of the project location) and Omaha, Nebraska (located approximately 205 miles from the project location). It is anticipated that additional craft workers needed during the construction phase will temporarily relocate to the east-central South Dakota area.

8. ADDITIONAL IMPACT ASSESSMENT

It is expected that workers relocating to east-central South Dakota during the construction phase will commute to the project site. Emissions associated with the increase in vehicle miles traveled, and emissions directly associated with the construction activities (e.g., grading, bulldozing, cranes, etc.) will increase overall air-shed emissions during the construction phase. The presence of temporary workers during the construction phase will likely cause short-term demand for services in area, including rental lodging, hotels, and restaurants. However, the construction phase is temporary and will not contribute to permanent growth-related emissions in the area. Therefore, the construction period is assumed to be short-term, with a primarily transient work force that does not contribute substantially to long-term growth.

Following the construction phase, there will be approximately 25 to 30 employees at the Deer Creek Station. Plant employees are expected to come from nearby rural communities in Brookings County, as well as the larger population centers in the nearby counties of Codington and Minnehaha. The 2000 population of Brookings, Deuel, Codington, Hamlin, Kingsbury, Lake, Moody, and Minnehaha counties was approximately 236,100 persons. The maximum construction force of 430 persons represents approximately 0.18% of the population in the 8-county area. The post-construction operation employees (25 - 30) represents approximately 0.011 to 0.013% of the population.

It is expected that a majority of the post-construction positions will be filled with persons already residing in the east-central South Dakota area, and that the additional permanent jobs will not add significantly to the overall population within the 8-county area. Because a majority of the permanent jobs are expected to be filled with persons already living in the area, secondary employment and commercial growth associated with the project (e.g., automotive repair, grocery stores, motels, equipment supply, etc.) are expected to be minimal. The additional permanent jobs are not expected to result in any residential construction or construction-related emissions.

No significant project-related industrial growth is expected to accompany the Deer Creek project. Project-related support services such as maintenance, cleaning, painting, and other related services already support existing industrial facilities in east-central South Dakota. Operating the Deer Creek Station is not expected to trigger significant expansion of the existing support services industry in the area.

The majority of growth-related emissions associated with the project are expected to be related to the increased workforce (e.g., vehicle emissions associated with commuting). With respect to permanent employee vehicle emissions, it is anticipated that most workers will commute an average of 25 miles to the facility. Vehicle emissions were estimated using average vehicle emission rates available in U.S.EPA's AP-42 Appendix I: Emission Sensitivity Tables (All Vehicles Combined). The AP-42 Appendix I emission factors were developed using U.S.EPA's Mobile5 model. Mobile5 estimates emissions of hydrocarbons (HC), NOx, and CO from passenger cars, motorcycles, light- and heavy-duty trucks. Using emission factors summarized in AP-42 Appendix I, increased vehicle emissions associated with permanent employees at the Deer Creek Station are expected to be in the range of 7.6 tpy (CO), 1.4 tpy (NO_x), and 1.0 tpy (VOC).

Growth-related secondary emissions associated with the project are expected to be minimal. Project-related industrial growth is not expected to be significant. The project will result in approximately 25 to 30 permanent jobs at the facility, however, the increase in permanent jobs is not expected to result in significant commercial or residential growth in east-central South Dakota. The project may result in a minimal increase in vehicle emissions associated with employee commuting, however, emissions associated with increased employment are minimal and will have no impact on overall emissions in the region.

8.3 Soils & Vegetation Analysis

PSD regulations require an analysis of air quality impacts on soils and vegetation in the vicinity of the proposed project. Potential effects of NO_2, CO associated with the Deer Creek project on the nearby vegetation and soil were examined.

The Deer Creek Station will be located in Brookings County in east-central South Dakota. East-central South Dakota is located in the Coteau des Prairies physiographic region of South Dakota. The area is characterized as a high land plateau that extends across the county in a southeasterly direction. Brookings County is part of the tall grass prairie and native vegetation is dominated by tall and mid grasses and forbs. Soil is the most important natural resource in the county. It provides a growing medium for crops and for the grass grazed by livestock. About 65% of the acreage in the county is used for cultivated crops, and 7% is used for tame pasture or as hayland. Dryland farming is dominant, with only about 3% of the land irrigated. Crops cultivated in the areas include corn, soybeans, and small grain. Other natural resources in the county are water, sand and gravel, and wildlife

The potential effects of the air emissions to vegetation within the immediate vicinity of Deer Creek were evaluated by comparing modeled ambient air quality impacts to scientific research examining the effects of pollution on vegetation. Evaluation of impacts on sensitive vegetation were performed by comparing

8. ADDITIONAL IMPACT ASSESSMENT

the predicted impacts attributable to the project with the screening levels presented in “A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals” (EPA 1980).[i]

The U.S.EPA screening procedure compares the maximum ambient concentrations associated with a proposed emissions source to the applicable screening concentrations. Maximum ambient air concentrations associated with the project were estimated using the Class II ambient air quality impact modeling described above. Modeled ambient air quality impacts were compared to the U.S.EPA screening values. Concentrations in excess of any of the screening concentrations would indicate that the source might have adverse impacts on plants, soils, or animals.

Results of the screening analysis are summarized in Table 8-8. As shown in the table, all potential impacts are modeled to be well below the screening levels. Most of the designated vegetation screening levels are equivalent to, or less stringent than, the NAAQS and/or PSD increments. Therefore, satisfaction of NAAQS and PSD increments also provides assurance that ambient air quality impacts will be below the sensitive vegetation screening levels.

Table 8-8
Ambient Air Quality Screening Concentrations for Soils and Vegetation

Pollutant	Averaging Period	Screening Concentration ($\mu g/m^3$)	Predicted Concentrations[(2)] ($\mu g/m^3$)
NO_2	4-hour	3,760	513.5
	1-month	564	64.7
	Annual	94	0.71
CO	Weekly[(1)]	1,800,000	236

[(1)] Modeled using the 8-hour averaging time
[(2)] Maximum concentration over 5-year period

9. PERMIT LIMITS

9.0 Proposed Emission Limits

Based on the review of applicable emission standards and regulations (Section 4.0), the BACT analysis (Section 5.0 and Appendix D), and results of the ambient air quality impact modeling, BEPC is proposing the following permit limits and compliance methods for the Deer Creek Station emission sources. Emission limits proposed below are in addition to the applicable regulatory limits summarized in Section 4.0.

9.1 Proposed Emission Limits – CT/HRSG

The Deer Creek CT/HRSG will be constructed and operated with the following emission control technologies:

- combustion controls (low-NO_x burners); and
- selective catalytic reduction;

In addition to the applicable regulatory limits and NSPS, to ensure compliance with the BACT determination and ambient air quality impact modeling results, BEPC is proposing the emission limits summarized in Tables 9-1 thru 9-3.

Table 9-1
Proposed CT/HRSG NOx Emission Limits

<table>
<tr><th colspan="5">Deer Creek CT/HRSG - NO_x</th></tr>
<tr><th rowspan="6">NO_x</th><th>Limit</th><th>Averaging Time</th><th>Applicability</th><th>Compliance Method</th></tr>
<tr><td>3.5 ppmvd @ 15% O_2</td><td>30-day rolling</td><td rowspan="2">Applicable during all normal operations, excluding startup and shutdown</td><td rowspan="4">Compliance with the continuous NO_x emission limits will be determined from CEMS data and calculated for the appropriate averaging time.</td></tr>
<tr><td>29.4 lb/hr</td><td>30-day rolling</td></tr>
<tr><td>65.5 lb/hr
(short-term maximum)</td><td>24-hour avg.</td><td>Applicable during CT startup/shutdown</td></tr>
<tr><td>116.6 tpy</td><td>12-mo. avg.</td><td>Applies to all CT/HRSG emissions, including startup/shutdown</td></tr>
</table>

9. PERMIT LIMITS

Table 9-2
Proposed CT/HRSG CO Emission Limits

Deer Creek CT/HRSG – CO				
	Limit	**Averaging Time**	**Applicability**	**Compliance Method**
CO	9.0 ppmvd (32.0 lb/hr)	30-day rolling	Applicable during all normal operations when not duct firing, excluding startup and shutdown	Compliance with the continuous CO emission limits will be determined from CEMS data and calculated for the appropriate averaging time.
	18.3 ppmvd (57.2.0 lb/hr)	30-day rolling	Applicable during all normal operations when duct firing, excluding startup and shutdown	
	337.1 lb/hr (short-term maximum)	24-hour avg.	Applicable during CT startup/shutdown	
	243.3 tpy	12-mo. avg.	Applies to all CT/HRSG emissions, including startup/shutdown	

Table 9-3
Proposed CT/HRSG PM Emission Limits

Deer Creek CT/HRSG – Total PM (filterable + condensible)				
	Limit	**Averaging Time**	**Applicability**	**Compliance Method**
PM	0.011 lb/mmBtu	3-hour avg.	Applicable during all normal operations, excluding startup and shutdown	Initial compliance test using reference stack test methods 201a/202, modified as approved by DENR to account for pseudoparticulates formed in the sampling train impingers. On-going compliance will be based on the initial stack test results and heat input to the CT/HRSG
	18.6 lb/hr	3-hour avg.	Applicable at all times when not duct firing, including startup and shutdown	
	23.2 lb/hr	3-hour avg.	Applicable at all times when duct firing, including startup and shutdown	
	80.0 tpy	12-mo. avg.	Applies to all CT/HRSG emissions, including startup/shutdown	

9. PERMIT LIMITS

9.2 Proposed Emission Limits – Diesel-Fired Stationary Engines and Inlet Air Heater

The emergency generator and fire-water pump will meet the applicable Stationary Compression Ignition Internal Combustion Engine (CI ICE) NSPS (40 CFR Part 60 Subpart IIII). The CI ICE NSPS limits emissions of NOx, PM, SO_2, CO, and HC from stationary diesel internal combustion engines. Provisions of the CI ICE NSPS apply to manufacturers, owners, and operators of stationary CI internal combustion engines. BEPC will be required to purchase engines certified by the manufacturer to meet the applicable emissions levels. Annual emissions from these diesel engines will also be reduced by limiting the annual hours of operation to 150 hours/year (each engine).

Emissions from the emergency inlet air heater will be limited by firing natural gas and limiting the annual hours of operation. As described above, the inlet air heater will be used to preheat the CT intake air under extremely cold ambient conditions (approximately -25 °F). Based on the preliminary design, it is expected that the heater will operate for 10 to 20 minutes during startup under these conditions. Emissions from the inlet air heater will be controlled by using combustion controls and limiting the annual hours of operation to 150 hours per year.

APPENDICES

Appendix A	DENR Permit Application Forms
Appendix B	Supporting Calculations for Emission Estimates
Appendix C	BACT Analysis
Appendix D	Class II Impact Modeling Results and Support Documentation

Basin Electric Power Cooperative

Deer Creek Station

PSD Air Quality Construction Permit Application

Appendix A

South Dakota Department of Environment and Natural Resources

Permit Application Forms

May 29, 2009

Basin Electric Power Cooperative
Deer Creek Station
PSD Air Quality Construction Permit Application
Appendix A – List of Forms

1. Air Quality Permit Application Form
   Title V (Part 70) Operating Permit
   General Information Form and Certification of Applicant Form

2. Air Quality Permit Application Form
   Boiler Turbine or Furnace
   (CT/HRSG #1 – EP01)

3. Air Quality Permit Application Form
   Miscellaneous Control Device
   (Low NOx Combustion and Selective Catalytic Reduction – CT/HRSG #1 – EP01)

4. Air Quality Permit Application Form
   Miscellaneous Process
   (Emergency Diesel Generator – EP02)

5. Air Quality Permit Application Form
   Miscellaneous Process
   (Fire Water Pump – EP03)

6. Air Quality Permit Application Form
   Miscellaneous Process
   (Emergency Inlet Gas Heater – EP04)

7. Air Quality Permit Application Form
   Storage Tanks
   (Emergency Diesel Generator Fuel Tank – TK-1)

8. Air Quality Permit Application Form
   Storage Tanks
   (Fire Water Pump Fuel Tank – TK-2)

South Dakota Department of Environment & Natural Resources
Protecting SD's Tomorrow...Today

Air Quality Permit Application Form
Title V (Part 70) Operating Permit

General Information Form
And
Certification of Applicant Form

SEND ALL MATERIALS TO:

SD Department of Environment and Natural Resources
Air Quality Program
523 East Capitol
Pierre, South Dakota 57501-3181

(Please complete shaded areas - if you have questions call (605) 773-3151)

GENERAL INFORMATION

If permit is being renewed or amended, give existing permit number:	
1. Facility name:	Deer Creek Station
2. Mailing address:	
Street and/or box number	1717 East Interstate Avenue
City, state, zip code	Bismarck, North Dakota 58503-0564
3. Facility location (if plant is portable, enter location at time of submittal):	
Street and city	6 miles southeast of White, South Dakota
Legal description and county	E 1/2 of the NW 1/4 of Sec. 25, Township 111 N, Range 48 W, Brookings Co
	(Quarter, Section, Township, Range)
4. Permit contact:	
Name/title	Jerry Menge, Air Quality Program Coordinator
Telephone number	(701) 223-0441
5. Facility contact, if different than permit contact (Person to contact for arranging inspections):	
Name/title	
Telephone number	
6. Responsible official:	
Name/title	Robert W. Holzwarth, Vice President of Operations
Telephone number	(701) 223-0441

A responsible official is defined as a president, vice president, secretary, or treasurer for a corporation; general partner or the proprietor for a partnership; and principal executive officer or ranking elected official for municipal, state, federal or public agency.

B. PLANT DESCRIPTION

1. Standard Industrial Classification Code (SIC code):

Primary SIC code: 4911 Secondary SIC code (if applicable):

Please contact the Department if unable to determine your SIC code.

2. Briefly describe the operations at the facility, including raw materials and finished products:

Natural gas-fired combustion turbine and heat recovery steam generator for electricity generation.

Please attach one copy, if available, of any prepared plans and the manufacturer's specifications of any equipment, including pollution control devices. If additional space is needed to describe operations, please attach the additional paper to this application.

3. A **new source or modification to an existing source** is required to demonstrate that the operation of the new source or modification will not prevent or interfere with the attainment or maintenance of an applicable ambient air quality standard. Please attach air dispersion modeling or other documents that will demonstrate the new source or modification will not prevent or interfere with the attainment or maintenance of an applicable ambient air quality standard.

Has air dispersion modeling been conducted (please check one)? X Yes ☐ No

If air dispersion modeling has been conducted, please attach a copy of the report to this application unless the Department has a copy already.

C. COMPLIANCE PLAN

If it is anticipated that a permitted unit will not be operating in compliance at the time of permit issuance, a proposed compliance plan shall be included with the application. The proposed compliance plan shall include a narrative description of the following:

1. The requirements (i.e., statutes, air quality rules, permit conditions, etc.) the source is not in compliance with at the time of submittal of this application or permit issuance;
2. How the facility intends to bring the unit(s) into compliance; and
3. A compliance schedule for when the source will achieve compliance with such requirements;

The compliance schedule must include a statement that progress reports will be submitted at least once every six months and must be at least as stringent as that contained in any judicial consent decree or administrative order to which the applicant is subject.

D. MAPS

For stationary sources only, please enclose a map or a drawing showing roadways, location of plant and the nearest residents in each direction from the source. Include other structures, which may be affected.

E. AIR QUALITY EMISSIONS SUMMARY

If air quality emissions are available, please complete the following table:

Pollutant	Actual (tons per year)	Potential Controlled (tons per year)	Potential Uncontrolled (tons per year)
Particulate		See Table 3-15	
Sulfur Dioxide		See Table 3-15	
Nitrogen Oxide		See Table 3-15	
Carbon Monoxide		See Table 3-15	
Volatile Organic Compounds		See Table 3-15	
Hazardous Air Pollutants (if applicable)			
		See Table 3-18	

Remember that potential emissions are calculated assuming that the permitted unit is operated 24 hours per day, 7 days per week, 52 weeks per year at maximum design capacity. Attach all calculations, MSDS sheets for all products containing volatile organic compounds and/or hazardous air pollutants, and other supporting documentation.

Please contact the Department if assistance is needed for calculating emissions for the permitted units such as emission factors, clarifying what potential emissions are, efficiency for control equipment, etc.

F. ADDITIONAL FORMS

1. The following forms must be completed for each piece of specific equipment at the facility and submitted with this form:

Boiler	Incinerator	Kiln Dryer
Miscellaneous Process	Paint Booth	Storage Tank

2. The following forms must be completed for each piece of specific air control equipment at the facility and submitted with this form:

Baghouse	Cyclone	Electrostatic Precipitator
Miscellaneous Control	Thermo Oxidizer	Wet Scrubber

3. A list of insignificant activities must be identified in this application. The insignificant activity form must be completed and submitted along with this application.

G. CERTIFICATION OF COMPLIANCE

I certify the following:

1. The methods such as monitoring, record keeping, reporting, and stack test performance results described within this application shall be used to determine continuous or intermittent compliance;
2. A compliance certification document will be submitted to the Department at least annually or at other times designated by the Department for the duration of the permit;
3. The source is in compliance and will continue to demonstrate compliance with all applicable requirements, except for those designated in the attached compliance plan (if applicable); and
4. This application is submitted in accordance with the provisions of the South Dakota Codified Laws 34A-1 and Administrative Rules of South Dakota 74:36. To the best of my knowledge, after reasonable inquiry, the statements and information contained in the application and supporting documents are true, accurate, and complete. In accordance with South Dakota Codified Laws 1-40-27, I have also enclosed a completed Certification of Applicant form.

Signature:		
Print Name:		Date
	Responsible Official	

CERTIFICATION OF APPLICANT

(please complete shaded areas - if you have questions call (605) 773-3151)

In the Matter of the Application of	Deer Creek Station
	(Facility Name)
State of	South Dakota
County of	Brookings

I, Robert W. Holzwarth, the applicant in the above matter after being duly sworn upon oath hereby certify the following information in regard to this application:

South Dakota Codified Laws Section 1-40-27 provides:

"The secretary may reject an application for any permit filed pursuant to Titles 34A or 45, including any application by any concentrated swine feeding operation for authorization to operate under a general permit, upon making a specific finding that:

(1) The applicant is unsuited or unqualified to perform the obligations of a permit holder based upon a finding that the applicant, any officer, director, partner or resident general manager of the facility for which application has been made:

(a) Has intentionally misrepresented a material fact in applying for a permit;

(b) Has been convicted of a felony or other crime involving moral turpitude;

(c) Has habitually and intentionally violated environmental laws of any state or the United States which have caused significant and material environmental damage;

(d) Has had any permit revoked under the environmental laws of any state or the United States; or

(e) Has otherwise demonstrated through clear and convincing evidence of previous actions that the applicant lacks the necessary good character and competency to reliably carry out the obligations imposed by law upon the permit holder; or

(2) The application substantially duplicates an application by the same applicant denied within the past five years which denial has not been reversed by a court of competent jurisdiction. Nothing in this subdivision may be construed to prohibit an applicant from submitting a new application for a permit previously denied, if the new application represents a good faith attempt by the applicant to correct the deficiencies that served as the basis for the denial in the original application.

All applications filed pursuant to Titles 34A and 45 shall include a certification, sworn to under oath and signed by the applicant, that he is not disqualified by reason of this section from obtaining a permit. In the absence of evidence to the contrary, that certification shall constitute a prima facie showing of the suitability and qualification of the applicant. If at any point in the application review, recommendation or hearing process, the secretary finds the applicant has intentionally made any material misrepresentation of fact in regard to this certification, consideration of the application may be suspended and the application may be rejected as provided for under this section.

Applications rejected pursuant to this section constitute final agency action upon that application and may be appealed to circuit court as provided for under chapter 1-26."

Pursuant to SDCL 1-40-27, I certify that I have read the forgoing provision of state law, and that I am not disqualified by reason of that provision from obtaining the permit for which application has been made.

Dated this		, day of		***, 20***	

Applicant (signature)

Subscribed and sworn before me this:

Dated this		, day of		, 20	

Notary Public (signature)

My commission expires:

(SEAL)

PLEASE ATTACH SHEET DISCLOSING ALL FACTS PERTAINING TO SDCL 1-40-27 (1) (a) THROUGH (e).
ALL VIOLATIONS MUST BE DISCLOSED, BUT WILL NOT AUTOMATICALLY RESULT IN THE REJECTION OF AN APPLICATION.

South Dakota Department of Environment & Natural Resources
Protecting SD's Tomorrow...Today

Air Quality Permit Application Form

Boiler Turbine or Furnace

This form is to be submitted, if necessary, along with the Title V (Part 70) Operating Permit or Minor Operating Permit.
(please complete shaded areas)

1. Facility identification (i.e., Boiler #1, Unit #1, etc):	CT/HRSG #1 – EP01		
2. Manufacturer:	TBD	Manufacture date:	TBD
3. Model number:	F-class (or equivalent)		

4. Type (i.e., steam boiler, simple cycle combustion turbine, generator, etc.)

Combustion Turbine

5. Maximum designed operating rate (name plate):

	CT: 1713 (LHV) Duct Burners: 615.2 (LHV)	million Btus per hour heat input	
or		horsepower with boiler efficiency:	
or		kilowatts with boiler efficiency:	

6. Check the appropriate box(es) for primary and secondary fuels:

X	Natural gas				Propane
	Distillate oil	Sulfur content		Weight percent	
	Residual oil	Sulfur content		Weight percent	
	Bituminous Coal		Subbituminous Coal		Lignite Coal
Coal sulfur content		Weight percent	Coal ash content		Weight percent
	Other (please specify)				

7. Has a stack test been conducted (check appropriate box)? [ ] Yes [X] No

If a stack test has been conducted, please attach a copy of the most recent stack test report to this application. If the Department already has a copy of the most recent stack test, please specify the date of most recent stack test.

Date of most recent stack test: NA

Control Equipment: If applicable, types of air pollution control equipment (Examples: baghouse, cyclone, wet scrubber, electrostatic precipitator, thermal oxidizer, miscellaneous control device, etc.).

Low NO_x Burners and Selective Catalytic Reduction (SCR)

Please complete the appropriate air quality permit application form for each type of control equipment that controls air emissions from this operation.

Stack Information: If this application is a renewal, contact the air program. We may have this information.

X- Coordinate or Easting:		feet	696,451	meters
Y- Coordinate or Northing:		feet	4,918,630	meters
Base Elevation of Stack:	1,850.5	feet	564.0	meters
Stack Height:	150	feet	45.72	meters
Exit Stack Diameter	19.0	feet	5.79	meters
Exit Stack Temperature	200	degrees Fahrenheit		

Exit Stack Velocity and/or Flow Rate:

Velocity:	62.6	feet per second	19.1	meters per second

and/or

Flow Rate:	1,065,424	actual cubic feet per minute	502.8	actual cubic meters per second

Air Quality Permit Application Form

Miscellaneous Control Device

This form is to be submitted, if necessary, along with the Title V (Part 70) Operating Permit, Minor Operating Permit, or the General Permits.

(please complete shaded areas)

Describe the miscellaneous control device and how it works:

Low NOx Combustion: reduces thermal NOx formation by lowering the overall flame temperature in the combustor
Selective Catalytic Reduction (SCR): Reduces NOx emissions by injecting NH_3 in the presence of a catalyst.

Equipment and processes served by this baghouse (please list all equipment and processes):

	Equipment and Processes
1.	CT/HRSG #1 – EP01
2.	
3.	
4.	
5.	

Manufacturer Information:

Manufacturer?	TBD		
Manufacturer date?	TBD	Installation date?	May 2010
Manufacturer's designed control efficiency?	approximately 90	%	

Miscellaneous Control Device Operation and Maintenance:

Pressure drop across control unit?	TBD	Inches water (minimum)		inches water (maximum)
Inlet Temperature?	400	Fahrenheit (minimum)	800	Fahrenheit (maximum)
Outlet Temperature?	400	Fahrenheit (minimum)	800	Fahrenheit (maximum)

Describe maintenance of control unit (use of visual inspections, maintenance schedule, etc.):

Maintenance and inspection will be performed in accordance with manufacturer's recommended procedures.

Stack Information: If this application is a renewal, contact the air program. We may have this information.

X- Coordinate or Easting: [1]		feet	or	696,451	meters
Y- Coordinate or Northing: [1]		feet	or	4,918,630	meters
Base Elevation of Stack: [1]	1,850.5	feet	or	564.0	meters
Stack Height:	150	feet	or	45.72	meters
Exit Stack Diameter	19.0	feet	or	5.79	meters
Exit Stack Temperature	200	degrees Fahrenheit			

Exit Stack Velocity and/or Flow Rate:

Velocity:	62.6	feet per second	19.1	meters per second
		and/or		
Flow Rate:	1,065,424	actual cubic feet per minute	502.8	actual cubic meters per second

[1] - Portable asphalt plants, rock crushers, or concrete plants do not have to provide the requested information in these categories.

Air Quality Permit Application Form

Miscellaneous Process

South Dakota Department of Environment & Natural Resources
Protecting SD's Tomorrow...Today

This form is to be submitted, if necessary, along with the Title V (Part 70) Operating Permit or Minor Operating Permit.
(please complete shaded areas)

1. Facility identification (i.e., Boiler #1, Unit #1, etc): Emergency Diesel Generator – EP02
2. Manufacturer: TBD — Manufacture date: TBD
3. Model number: TBD
4. Type (i.e., steam boiler, simple cycle combustion turbine, generator, etc.)

Emergency Diesel Generator

5. Maximum designed operating rate (name plate):

	million Btus per hour heat input
or	horsepower
or 2000	kilowatts

6. Check the appropriate box(es) for primary and secondary fuels:

[ ] Natural gas			[ ] Propane	
[X] Distillate oil	Sulfur content	0.05	Weight percent	
[ ] Residual oil	Sulfur content		Weight percent	
[ ] Bituminous Coal	[ ] Subbituminous Coal		[ ] Lignite Coal	
Coal sulfur content		Weight percent	Coal ash content	Weight percent
[ ] Other (please specify)				

7. Has a stack test been conducted (check appropriate box)? [ ] Yes [X] No

If a stack test has been conducted, please attach a copy of the most recent stack test report to this application. If the Department already has a copy of the most recent stack test, please specify the date of most recent stack test.

Date of most recent stack test: NA

Control Equipment: If applicable, types of air pollution control equipment (Examples: baghouse, cyclone, wet scrubber, electrostatic precipitator, thermal oxidizer, miscellaneous control device, etc.).

NA

Please complete the appropriate air quality permit application form for each type of control equipment that controls air emissions from this operation.

Stack Information: If this application is a renewal, contact the air program. We may have this information.

X- Coordinate or Easting:		feet	696,369	meters
Y- Coordinate or Northing:		feet	4,918,531	meters
Base Elevation of Stack:	1,850.5	feet	564.0	meters
Stack Height:	15	feet	4.57	meters
Exit Stack Diameter	1.43	feet	0.43	meters
Exit Stack Temperature	987	degrees Fahrenheit		

Exit Stack Velocity and/or Flow Rate:

Velocity:	135	feet per second	41.1	meters per second
		and/or		
Flow Rate:	12,881	actual cubic feet per minute	6.1	actual cubic meters per second

Department of Environment & Natural Resources
Protecting SD's Tomorrow...Today

Air Quality Permit Application Form

Miscellaneous Process

This form is to be submitted, if necessary, along with the Title V (Part 70) Operating Permit or Minor Operating Permit.

(please complete shaded areas)

1. Facility identification (i.e., Boiler #1, Unit #1, etc):	Fire Water Pump – EP03		
2. Manufacturer:	TBD	Manufacture date:	TBD
3. Model number:	TBD		

4. Type (i.e., steam boiler, simple cycle combustion turbine, generator, etc.)

Emergency Diesel Generator

5. Maximum designed operating rate (name plate):

		million Btus per hour heat input
or	577	horsepower
or		kilowatts

6. Check the appropriate box(es) for primary and secondary fuels:

	Natural gas				Propane
X	Distillate oil	Sulfur content	0.05	Weight percent	
	Residual oil	Sulfur content		Weight percent	
	Bituminous Coal		Subbituminous Coal		Lignite Coal
	Coal sulfur content		Weight percent	Coal ash content	Weight percent
	Other (please specify)				

7. Has a stack test been conducted (check appropriate box)? [ ] Yes [X] No

If a stack test has been conducted, please attach a copy of the most recent stack test report to this application. If the Department already has a copy of the most recent stack test, please specify the date of most recent stack test.

Date of most recent stack test: NA

Control Equipment: If applicable, types of air pollution control equipment (Examples: baghouse, cyclone, wet scrubber, electrostatic precipitator, thermal oxidizer, miscellaneous control device, etc.).

NA

Please complete the appropriate air quality permit application form for each type of control equipment that controls air emissions from this operation.

Stack Information: If this application is a renewal, contact the air program. We may have this information.

X- Coordinate or Easting:		feet	696,494	meters
Y- Coordinate or Northing:		feet	4,918,705	meters
Base Elevation of Stack:	1,850.5	feet	564.0	meters
Stack Height:	30	feet	9.14	meters
Exit Stack Diameter	0.61	feet	0.18	meters
Exit Stack Temperature	845	degrees Fahrenheit		

Exit Stack Velocity and/or Flow Rate:

Velocity:	135	feet per second	41.1	meters per second

and/or

Flow Rate:	2,339	actual cubic feet per minute	1.1	actual cubic meters per second

Air Quality Permit Application Form

Miscellaneous Process

This form is to be submitted, if necessary, along with the Title V (Part 70) Operating Permit or Minor Operating Permit.

(please complete shaded areas)

1. Facility identification (i.e., Boiler #1, Unit #1, etc): Emergency Inlet Air Heater – EP04
2. Manufacturer: TBD — Manufacture date: TBD
3. Model number: TBD
4. Type (i.e., steam boiler, simple cycle combustion turbine, generator, etc.)

Emergency Diesel Generator

5. Maximum designed operating rate (name plate):

	25.0	million Btus per hour heat input
or		horsepower
or		kilowatts

6. Check the appropriate box(es) for primary and secondary fuels:

X	Natural gas			Propane
	Distillate oil	Sulfur content		Weight percent
	Residual oil	Sulfur content		Weight percent
	Bituminous Coal		Subbituminous Coal	Lignite Coal
	Coal sulfur content		Weight percent	Coal ash content — Weight percent
	Other (please specify)			

7. Has a stack test been conducted (check appropriate box)? [ ] Yes [X] No

If a stack test has been conducted, please attach a copy of the most recent stack test report to this application. If the Department already has a copy of the most recent stack test, please specify the date of most recent stack test.

Date of most recent stack test: NA

Control Equipment: If applicable, types of air pollution control equipment (Examples: baghouse, cyclone, wet scrubber, electrostatic precipitator, thermal oxidizer, miscellaneous control device, etc.).

NA

Please complete the appropriate air quality permit application form for each type of control equipment that controls air emissions from this operation.

Stack Information: If this application is a renewal, contact the air program. We may have this information.

X- Coordinate or Easting:		feet	696,451	meters
Y- Coordinate or Northing:		feet	4,918,633	meters
Base Elevation of Stack:	1,850.5	feet	564.0	meters
Stack Height:	30	feet	9.14	meters
Exit Stack Diameter	1.55	feet	0.47	meters
Exit Stack Temperature	300	degrees Fahrenheit		

Exit Stack Velocity and/or Flow Rate:

Velocity:	85	feet per second	25.9	meters per second

and/or

Flow Rate:	7,605	actual cubic feet per minute	3.6	actual cubic meters per second

Air Quality Permit Application Form

Storage Tanks

South Dakota Department of Environment & Natural Resources
Protecting SD's Tomorrow...Today

This form is to be submitted, if necessary, along with the Title V (Part 70) Operating Permit or Minor Operating Permit.
(please complete shaded areas)

1. Facility identification (i.e., Tank #1, Unit #1, etc)? Emergency Diesel Generator Fuel Tank – TK01
2. Manufacturer? TBD
3. Construction date? TBD 4. Model number? TBD
5. Check appropriate box: [X] Aboveground [ ] Underground
6. Maximum designed storage capacity? 3000 gallons
7. Check the appropriate box for the type of liquid stored in the storage tank:

X	Distillate oil		Residual oil
	Ethanol		JP8 Jet Fuel
	Other (please specify)		

8. Maximum true vapor pressure of liquid?

		millimeters mercury
or	0.009	pounds per square inch absolute
or		kilo Pascal

9. Have plans and specifications been submitted to the Department? [ ] Yes [X*] No

If no, please attach a copy of the plans and design specifications to the application.

10. If applicable, types of air pollution control equipment (i.e., wet scrubber, thermal oxidizer, etc.):

NA

Please complete the appropriate air quality permit application form for each type of control equipment that controls air emissions from this operation.

*Plans and design specifications will be submitted to the Department to supplement the permit application when they become available.

Air Quality Permit Application Form

Storage Tanks

This form is to be submitted, if necessary, along with the Title V (Part 70) Operating Permit or Minor Operating Permit.

(please complete shaded areas)

1. Facility identification (i.e., Tank #1, Unit #1, etc)? Fire Water Pump Fuel Tank – TK02

2. Manufacturer? TBD

3. Construction date? TBD 4. Model number? TBD

5. Check appropriate box: [X] Aboveground [ ] Underground

6. Maximum designed storage capacity? 700 gallons

7. Check the appropriate box for the type of liquid stored in the storage tank:

X	Distillate oil		Residual oil
	Ethanol		JP8 Jet Fuel
	Other (please specify)		

8. Maximum true vapor pressure of liquid?

		millimeters mercury
or	0.009	pounds per square inch absolute
or		kilo Pascal

9. Have plans and specifications been submitted to the Department? [ ] Yes [X*] No

If no, please attach a copy of the plans and design specifications to the application.

10. If applicable, types of air pollution control equipment (i.e., wet scrubber, thermal oxidizer, etc.):

NA

Please complete the appropriate air quality permit application form for each type of control equipment that controls air emissions from this operation.

*Plans and design specifications will be submitted to the Department to supplement the permit application when they become available.

Basin Electric Power Cooperative

BASIN ELECTRIC POWER COOPERATIVE

Deer Creek Station
PSD Air Quality Construction Permit Application

Appendix B
Emission Calculations

Prepared by:

Sargent & Lundy, LLC
Chicago, Illinois

Sargent & Lundy LLC

May 29, 2009

Appendix C – List of Tables

Table	Description
B-1	CT/HRSG Emission Cases and Assumptions
B-2	CT/HRSG Emissions - Full Load Cases with and without Duct Firing
B-3	CT/HRSG Emissions – Part Load Cases
B-4	CT/HRSG Emission Summaries
B-5	Auxiliary Combustion Sources – Cases and Assumptions
B-6	Emergency Diesel Generator – Criteria Pollutant Emissions
B-7	Emergency Diesel Generator – Non-Criteria Pollutant Emissions
B-8	Diesel-Fired Fire Water Pump – Criteria Pollutant Emissions
B-9	Diesel-Fired Fire Water Pump – Non-Criteria Pollutant Emissions
B-10	Emergency Inlet Air Heater – Criteria Pollutant Emissions
B-11	Emergency Inlet Air Heater – Non-Criteria Pollutant Emissions
B-12	CT/HRSG Startup Emission Calculation – Emissions Summary
B-13	CT/HRSG Cold Startup NOx Emission Details
B-14	CT/HRSG Cold Startup CO Emission Details
B-15	CT/HRSG Cold Startup VOC Emission Details
B-16	CT/HRSG Cold Startup PM Emission Details
B-17	CT/HRSG Warm Startup NOx Emission Details
B-18	CT/HRSG Warm Startup CO Emission Details
B-19	CT/HRSG Warm Startup VOC Emission Details
B-20	CT/HRSG Warm Startup PM Emission Details
B-21	CT/HRSG Cold Startup NOx and CO Emission Details
B-22	CT/HRSG Cold Startup VOC and PM Emission Details

Table B-1
Deer Creek Station
CT/HRSG Emission Calculation Cases and Assumptions

Basis:

1. Emission estimates are based on one (1) GE 7FA frame combustion turbine, 1 x 1 x 1 combined cycle configuration.
2. Assumed single fuel: natural gas.
3. The NGCC facility will be designed with air cooled condensing (ACC).
4. Emission calculations are based on heat balances prepared by S&L for the following cases:

	100% Load w/ Duct Firing	100% Load w/ No Firing	75% Load	50% Load	25% Load
Winter Extreme: 41 oF	Case 2	Case 1			
Annual Average: 43 oF	Case 4	Case 3	Case 12	Case 13	Case 14
Summer Conditions: 94 oF	Case 6	Case 5	Case 15	Case 16	Case 17
Summer Extreme: 109 oF	Case 8	Case 7			

Notes:

MBtu = 10^6 Btu

1. SO_2 emissions were calculated based on the fuel sulfur content and assuming 100% conversion of fuel S to SO_2.
2. VOC per 40 CFR, Subpart F, Section 51.100 (s)
3. Assumed 8% SO_2 to SO_3 oxidation during combustion process for natural gas.
4. The CT PM emission rate (lb/mmBtu) was calculated based emission an emission rate of 9.0 lb/hr PM at full load provided by the CT vendor.
   The HRSG PM emission rate (lb/mmBtu) was based on emissions information provided by the CT vendor.
   The PM emission rates provided by the CT/HRSG vendors were for filterable PM only per US EPA Method 201/201A.
5. Potential annual emissions were calculated assuming 8760 hours of operation per year.
6. Assumed 4% SO_2 to SO_3 oxidation across the SCR.
7. On units equipped with SCR, assumed 100% conversion of SO_3 to $(NH_4)_2SO_4$.
8. Condensible PM10: assumed $(NH_4)_2SO_4$ is captured as condensible PM10 (on units with SCR), and SO3 is captured as condensible PM10 on units with no SCR.
9. Back half particulate matter per US EPA Method 202
10. Assume back half equals front half plus ammonium sulfate or SO_3.
11. Total PM10 is equal to filterable plus condensible.
12. Assumed aqueous ammonia purity of 19.5%
13. Assuming an Internal Stack Diameter of 19 feet.
14. Assuming a Stack Exhaust Temperature or 200 F.

Table B-2
Deer Creek Station /HRSG Emission Calculations - Full Load Cases with and without Duct Firing

		BASE LOAD CASES							
		Case 1 Winter Extreme Case -41 °F Base Load Unfired	Case 2 Winter Extreme Case -41 °F Base Load Duct Firing	Case 3 Annual Average 43 °F Base Load Unfired	Case 4 Annual Average 43 °F Base Load Duct Firing	Case 5 Summer 94 °F Base Load Unfired	Case 6 Summer 94 °F Base Load Duct Firing	Case 7 Record Summer 109 °F Base Load Unfired	Case 8 Record Summer 109 °F Base Load Duct Firing
Number of Combustion Turbines		1	1	1	1	1	1	1	1
Maximum Annual Hours of Operation	hours	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
SITE CONDITIONS									
Ambient Temperature	°F	-41	-41	43	43	94	94	109	109
Relative Humidity	%	100	100	64	64	38	38	23	23
Site Elevation	feet	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850
Site Pressure	psia	13.76	13.76	13.76	13.76	13.76	13.76	13.76	13.76
FACILITY CONDITIONS									
CT Fuel Type		Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CT Model		GE-PG7241(FA)	GE-PG7241(FA)	GE-PG7241(FA)	GE-PG7241(FA)	GE-PG7241(FA)	GE-PG7241(FA)	GE-PG7241(FA)	GE-PG7241(FA)
CT Load		Base	Base	Base	Base	Base	Base	Base	Base
CT Gross Power Output (per CT)	kW	184,557	184,557	166,178	166,178	150,600	150,600	147,900	147,900
CT Heat Consumption (LHV)	MMBtu/hr (LHV)	1,713.0	1,713.0	1,541.0	1,541.0	1,434.0	1,434.0	1,416.0	1,416.0
CT Heat Consumption (HHV)	MBtu/hr	1,901.4	1,901.4	1,710.4	1,710.4	1,591.7	1,591.7	1,571.7	1,571.7
CT Fuel Flow Rate	lb/hr	83,602	83,602	75,207	75,207	69,985	69,985	69,107	69,107
CT Fuel Flow Rate	Mscf/hr	1.90	1.90	1.71	1.71	1.59	1.59	1.57	1.57
CT Exhaust Gas Flow Rate	lb/hr	3,898,000	3,898,000	3,489,000	3,489,000	3,231,002	3,231,002	3,190,000	3,190,000
CT Exhaust Gas Temperature	°F	1,030	1,030	1,100	1,100	1,137	1,137	1,143	1,143
DB Heat Consumption (LHV)	MBtu/hr	0.0	297.9	0.0	511.1	0.0	610.4	0.0	615.2
DB Heat Consumption (HHV)	MBtu/hr	0.0	330.7	0.0	567.3	0.0	677.5	0.0	682.8
DB Fuel Flow Rate	lb/hr	0	14,539	0	24,944	0	29,790	0	30,024
DB Fuel Flow Rate	Mscf/hr	0.00	0.33	0.00	0.57	0.00	0.68	0.00	0.68
Gross Steam Turbine Output	kW	85,326	122,116	83,505	142,723	79,936	152,860	74,632	146,127
Total Gross Plant Electrical Output	kW	269,883	306,673	249,683	308,901	230,536	303,460	222,532	294,027
Total Auxiliry Power	kW	5,390	6,393	6,507	8,528	10,001	10,884	10,002	10,904
Net Plant Electrical Output	kW	264,493	300,280	243,176	300,373	220,535	292,576	212,530	283,123
Net Plant Electrical Heat Rate, LHV	Btu/kWh_{net} (LHV)	6,477	6,697	6,337	6,832	6,502	6,988	6,663	7,174
NATURAL GAS ANALYSIS									
Fuel LHV	Btu/lb	20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490
Fuel HHV	Btu/lb	22,743	22,743	22,743	22,743	22,743	22,743	22,743	22,743
Fuel LHV	Btu/ft^3	902.9	902.9	902.9	902.9	902.9	902.9	902.9	902.9
Fuel HHV	Btu/ft^3	1,002.1	1,002.1	1,002.1	1,002.1	1,002.1	1,002.1	1,002.1	1,002.1
HHV/LHV Ratio		1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11
Total Sulfur, S (Note 1)	$grains/100\ ft^3$	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50

Table B-2: Full Load Cases with and without Duct Firing - continued

		BASE LOAD CASES							
		Case 1 Winter Extreme Case -41 °F Base Load Unfired	Case 2 Winter Extreme Case -41 °F Base Load Duct Firing	Case 3 Annual Average 43 °F Base Load Unfired	Case 4 Annual Average 43 °F Base Load Duct Firing	Case 5 Summer 94 °F Base Load Unfired	Case 6 Summer 94 °F Base Load Duct Firing	Case 7 Record Summer 109 °F Base Load Unfired	Case 8 Record Summer 109 °F Base Load Duct Firing
COMBUSTION TURBINE EXHAUST ANALYSIS									
Argon, Ar	% vol	0.91	0.91	0.91	0.91	0.88	0.88	0.87	0.87
Nitrogen, N_2	% vol	75.20	75.20	74.73	74.73	73.12	73.12	72.95	72.95
Oxygen, O_2	% vol	12.80	12.80	12.66	12.66	12.25	12.25	12.21	12.21
Carbon Dioxide, CO_2	% vol	3.76	3.76	3.76	3.76	3.75	3.75	3.75	3.75
Water, H_2O	% vol	7.33	7.33	7.94	7.94	10.00	10.00	10.22	10.22
Total		*100.0*	*100.0*	*100.0*	*100.0*	*100.0*	*100.0*	*100.0*	*100.0*
Molecular weight	lb/lbmol	28.50	28.50	28.43	28.43	28.21	28.21	28.18	28.18
COMBUSTION TURBINE EMISSIONS (per CT)									
NO_X	ppmvd @ 15% O_2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
NO_X	ppmvd	10.8	10.8	10.9	10.9	11.1	11.1	11.1	11.1
NO_X as NO_2	lb/hr	63.0	63.0	56.6	56.6	52.6	52.6	51.9	51.9
CO	ppmvd @ 15% O_2	7.5	7.5	7.4	7.4	7.3	7.3	7.3	7.3
CO	ppmvd	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
CO	lb/hr	32.0	32.0	28.5	28.5	26.0	26.0	25.6	25.6
VOC (non-methane, non-ethane) (Note 2)	ppmvd @ 15% O_2	1.26	1.26	1.25	1.25	1.26	1.26	1.26	1.26
VOC (non-methane, non-ethane)	ppmvd	1.51	1.51	1.52	1.52	1.56	1.56	1.56	1.56
VOC (non-methane, non-ethane)	ppmvw	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
VOC as CH_4	lb/hr	3.07	3.07	2.76	2.76	2.57	2.57	2.54	2.54
SO_2	ppmvd @ 15% O_2	0.27	0.27	0.28	0.28	0.28	0.28	0.27	0.27
SO_2	ppmvd	0.33	0.33	0.34	0.34	0.34	0.34	0.34	0.34
SO_2	lb/hr	2.71	2.71	2.44	2.44	2.27	2.27	2.24	2.24
SO_3 Oxidation (Note 3)	%	8%	8%	8%	8%	8%	8%	8%	8%
SO_3	ppmvd @ 15% O_2	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
SO_3	ppmvd	0.026	0.026	0.027	0.027	0.027	0.027	0.027	0.027
SO_3	lb/hr	0.264	0.264	0.244	0.244	0.223	0.223	0.220	0.220
Formaldehyde, HCHO (AP-42 Table 3.1-3)	lb/MBtu (HHV)	7.1E-04	7.1E-04	7.1E-04	7.1E-04	7.1E-04	7.1E-04	7.1E-04	7.1E-04
Formaldehyde, HCHO	lb/hr	1.35	1.35	1.21	1.21	1.13	1.13	1.12	1.12
PM10									
PM10-filterable (Note 4)	lb/MBtu (HHV)	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475
PM10-filterable	lb/hr	9.0	9.0	8.1	8.1	7.6	7.6	7.5	7.5
PM10-condensible (Note 4, 9)	lb/MBtu (HHV)	0.0047	0.0047	0.0047	0.0047	0.0047	0.0047	0.0047	0.0047
PM10-condensible (Note 4, 9)	lb/hr	8.9	8.9	8.0	8.0	7.5	7.5	7.4	7.4

Table B-2: Full Load Cases with and without Duct Firing - continued

		BASE LOAD CASES							
		Case 1 Winter Extreme Case -41 °F Base Load Unfired	Case 2 Winter Extreme Case -41 °F Base Load Duct Firing	Case 3 Annual Average 43 °F Base Load Unfired	Case 4 Annual Average 43 °F Base Load Duct Firing	Case 5 Summer 94 °F Base Load Unfired	Case 6 Summer 94 °F Base Load Duct Firing	Case 7 Record Summer 109 °F Base Load Unfired	Case 8 Record Summer 109 °F Base Load Duct Firing
DUCT BURNER EMISSIONS (per CT/HRSG)									
DB Heat Consumption (HHV)	MBtu/hr	0.0	330.7	0.0	567.3	0.0	677.5	0.0	682.8
DB Heat Consumption (HHV)	Mscf/hr	0.00	0.33	0.0	0.6	0.0	0.7	0.0	0.7
NO_X	lb/MBtu, HHV	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
NO_X	lb/hr	0.0	16.5	0.0	28.4	0.0	33.9	0.0	34.1
CO	lb/MBtu, HHV	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
CO	lb/hr	0.0	16.5	0.0	28.4	0.0	33.9	0.0	34.1
VOC (non-methane, non-ethane) (Note 2)	lb/MBtu, HHV	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020
VOC as CH_4	lb/hr	0.00	6.61	0.00	11.35	0.00	13.55	0.00	13.66
SO_2	lb/hr	0.00	0.47	0.00	0.81	0.00	0.97	0.00	0.97
SO_3 Oxidation	%	8%	8%	8%	8%	8%	8%	8%	8%
SO_3	lb/hr	0.000	0.047	0.000	0.081	0.000	0.097	0.000	0.097
Formaldehyde, HCHO (AP-42 Table 1.4-3)	lb/Mscf	7.50E-02	7.50E-02	7.50E-02	7.50E-02	7.50E-02	7.50E-02	7.50E-02	7.50E-02
Formaldehyde, HCHO	lb/hr	0.000	0.025	0.000	0.043	0.000	0.051	0.000	0.051
PM10									
PM10-filterable (Note 4)	lb/MBtu, HHV	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
PM10-filterable	lb/hr	0.0	1.7	0.0	2.8	0.0	3.4	0.0	3.4
PM10-condensible (AP-42, Table 1.4-2)	lb/Mscf	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
PM10-condensible	lb/hr	0.0	1.9	0.0	3.2	0.0	3.9	0.0	3.9
POST DUCT BURNER EMISSIONS (per CT/HRSG)									
NO_X	ppmvd @ 15% O_2	9.0	9.7	9.0	10.2	9.0	10.4	9.0	10.4
NO_X	ppmvd	10.8	13.7	10.9	16.6	11.1	18.5	11.1	18.7
NO_X as NO_2	lb/hr	63.0	79.5	56.6	85.0	52.6	86.5	51.9	86.0
CO	ppmvd @ 15% O_2	7.5	9.7	7.4	11.2	7.3	11.8	7.3	11.8
CO	ppmvd	9.0	13.8	9.0	18.2	9.0	21.1	9.0	21.3
CO	lb/hr	32.0	48.5	28.5	56.9	26.0	59.9	25.6	59.7
VOC (non-methane, non-ethane) (Note 2)	ppmvd @ 15% O_2	1.26	3.38	1.25	4.84	1.25	5.54	1.26	5.61
VOC (non-methane, non-ethane)	ppmvd	1.51	4.79	1.52	7.89	1.55	9.91	1.56	10.11
VOC (non-methane, non-ethane)	ppmvw	1.40	4.38	1.40	7.08	1.40	8.64	1.40	8.78
VOC as CH_4	lb/hr	3.07	9.68	2.76	14.11	2.57	16.12	2.54	16.20

Table B-2: Full Load Cases with and without Duct Firing - continued

		BASE LOAD CASES							
		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
		Winter Extreme Case	Winter Extreme Case	Annual Average	Annual Average	Summer	Summer	Record Summer	Record Summer
		-41 °F	-41 °F	43 °F	43 °F	94 °F	94 °F	109 °F	109 °F
		Base Load Unfired	Base Load Duct Firing	Base Load Unfired	Base Load Duct Firing	Base Load Unfired	Base Load Duct Firing	Base Load Unfired	Base Load Duct Firing
SO_2	ppmvd @ 15% O_2	0.27	0.28	0.28	0.28	0.28	0.28	0.27	0.28
SO_2	ppmvd	0.33	0.39	0.34	0.45	0.34	0.50	0.34	0.50
SO_2	lb/hr	2.71	3.18	2.44	3.25	2.27	3.24	2.24	3.21
SO_3	ppmvd @ 15% O_2	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
SO_3	ppmvd	0.026	0.031	0.027	0.036	0.027	0.039	0.027	0.040
SO_3	lb/hr	0.264	0.31	0.24	0.33	0.22	0.32	0.22	0.32
Formaldehyde, HCHO	lb/hr	1.350	1.375	1.210	1.253	1.130	1.181	1.120	1.171
PM10									
PM10-filterable	lb/hr	9.0	10.7	8.1	10.9	7.6	11.0	7.5	10.9
PM10-condensible	lb/hr	8.9	10.8	8.0	11.2	7.5	11.4	7.4	11.3
POST SCR EMISSIONS (per CT/HRSG)									
Are NOx Emissions Controlled with SCR?	Yes/No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
If SCR, Controlled NOx Emission Rate	ppmvd @ 15% O_2	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
If SCR, Maximum NH_3 Slip	ppmvd @ 15% O_2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Hours of Operation (Note 5)	hours/year	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
NO_X	ppmvd @ 15% O_2	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
NO_X Removal Efficiency	% decrease	60.0%	60.0%	60.0%	70.0%	60.0%	70.0%	60.0%	70.0%
NO_X	ppmvd	4.2	5.0	4.2	5.7	4.3	6.3	4.3	6.3
NO_X	lb/hr	24.5	29.0	21.8	29.2	20.4	29.4	20.1	29.0
NO_X	lb/mmBtu (HHV)	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
NO_X	ton/yr	107.3	127.0	95.5	127.9	89.4	128.8	88.0	127.0
NH_3	ppmvd @ 15% O_2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NH_3	ppmvd	6.0	7.1	6.1	8.2	6.2	8.9	6.2	9.0
NH_3	lb/hr	13.0	15.2	11.7	15.6	10.9	15.4	10.7	15.3
NH_3	lbmol/hr	0.76	0.89	0.69	0.92	0.64	0.90	0.63	0.90
NH_3	ton/yr	56.9	66.6	51.2	68.3	47.7	67.5	46.9	67.0
CO	ppmvd @ 15% O_2	7.5	9.7	7.4	11.2	7.3	11.8	7.3	11.8
CO	ppmvd	9.0	13.8	9.0	18.3	9.0	21.1	9.0	21.3
CO	lb/hr	32.0	48.7	28.5	57.2	26.0	59.9	25.6	59.6
CO	lb/mmBtu (HHV)	0.017	0.022	0.017	0.025	0.016	0.026	0.016	0.026
CO	ton/yr	140.2	213.3	124.8	250.5	113.9	262.4	112.1	261.0

Table B-2: Full Load Cases with and without Duct Firing - continued

		BASE LOAD CASES							
		Case 1 Winter Extreme Case -41 °F Base Load Unfired	Case 2 Winter Extreme Case -41 °F Base Load Duct Firing	Case 3 Annual Average 43 °F Base Load Unfired	Case 4 Annual Average 43 °F Base Load Duct Firing	Case 5 Summer 94 °F Base Load Unfired	Case 6 Summer 94 °F Base Load Duct Firing	Case 7 Record Summer 109 °F Base Load Unfired	Case 8 Record Summer 109 °F Base Load Duct Firing
VOC (non-methane, non-ethane) (Note 2)	ppmvd @ 15% O_2	1.26	3.38	1.25	4.84	1.25	5.54	1.26	5.61
VOC (non-methane, non-ethane)	ppmvd	1.51	4.79	1.51	7.90	1.54	9.90	1.56	10.11
VOC as CH_4	lb/hr	3.07	9.68	2.74	14.13	2.55	16.10	2.54	16.20
VOC as CH_4	lb/mmBtu (HHV)	0.0016	0.0043	0.0016	0.0062	0.0016	0.0071	0.0016	0.0072
VOC as CH_4	ton/yr	13.4	42.4	12.0	61.9	11.2	70.5	11.1	71.0
SO_2	ppmvd @ 15% O_2	0.27	0.28	0.28	0.28	0.28	0.28	0.27	0.28
SO_2	ppmvd	0.33	0.39	0.34	0.45	0.34	0.50	0.34	0.50
SO_2	lb/hr	2.71	3.18	2.44	3.25	2.27	3.24	2.24	3.21
SO_2	lb/mmBtu (HHV)	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014
SO_2	ton/yr	11.9	13.9	10.7	14.2	9.9	14.2	9.8	14.1
SO_3 Oxidation across SCR (Note 6)	% increase	4%	4%	4%	4%	4%	4%	4%	4%
SO_3 Oxidation across SCR	lb/hr	0.135	0.159	0.122	0.162	0.113	0.162	0.112	0.160
SO_3	ppmvd @ 15% O_2	0.032	0.033	0.034	0.034	0.033	0.033	0.033	0.033
SO_3	ppmvd	0.039	0.047	0.041	0.055	0.041	0.059	0.041	0.060
SO_3	lb/hr	0.40	0.47	0.37	0.49	0.34	0.48	0.33	0.48
SO_3	lbmol/hr	5.00E-03	5.87E-03	4.62E-03	6.12E-03	4.25E-03	6.00E-03	4.12E-03	6.00E-03
H_2SO_4, Sulfuric Acid Mist	lb/hr	0.49	0.58	0.45	0.60	0.42	0.59	0.40	0.59
H_2SO_4, Sulfuric Acid Mist	ton/yr	2.15	2.54	1.97	2.63	1.84	2.58	1.75	2.58
$(NH_4)_2SO_4$, Ammonium Sulfate (Note 7, 8)	lb/hr	0.66	0.78	0.61	0.81	0.56	0.79	0.54	0.79
$(NH_4)_2SO_4$, Ammonium Sulfate (Note 7, 8)	ton/yr	2.89	3.42	2.67	3.55	2.45	3.46	2.37	3.46
Formaldehyde, HCHO	lb/hr	1.35	1.38	1.21	1.25	1.13	1.18	1.12	1.17
Formaldehyde, HCHO	ton/yr	5.91	6.04	5.30	5.48	4.95	5.17	4.91	5.12
Particulate Matter Emissions									
PM10-filterable	lb/hr	9.00	10.7	8.1	10.9	7.6	11.0	7.5	10.9
PM10-filterable	lb/mmBtu (HHV)	0.0047	0.0048	0.0047	0.0048	0.0048	0.0048	0.0048	0.0048
PM10-filterable	ton/yr	39.4	46.9	35.5	47.7	33.3	48.2	32.9	47.7
PM10-condensible (Note 10)	lb/hr	9.6	11.6	8.6	12.0	8.1	12.2	7.9	12.1
PM10-condensible (Note 10)	ton/yr	42.0	50.8	37.7	52.6	35.5	53.4	34.6	53.0
Total PM10 (filterable + condensible) (Note 11)	lb/hr	18.6	22.3	16.7	22.9	15.7	23.2	15.4	23.0
Total PM10 (filterable + condensible) (Note 11)	lb/mmBtu (HHV)	0.0098	0.0100	0.0098	0.0101	0.0099	0.0102	0.0098	0.0102
Total PM10	ton/yr	81.5	97.7	73.1	100.3	68.8	101.6	67.5	100.7
CO_2	lb/hr	226,320	264,765	203,047	269,006	189,045	267,818	186,810	266,202
CO_2	ton/yr	991,280	1,159,669	889,346	1,178,246	828,016	1,173,042	818,228	1,165,964
Aqueous Ammonia (per CT/HRSG)									
Purity (Note 13)	%	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Consumption	lb/hr	139.8	173.8	126.1	185.9	117.0	187.4	115.2	186.7
Stack Conditions (per CT/HRSG)									
Flow	lb/hr	3,898,140	3,912,713	3,489,126	3,514,130	3,231,119	3,260,979	3,190,115	3,220,211

Table B-3
Deer Creek CT/HRSG Emission Calculations
Part Load Cases

		PART LOAD CASES				
		Case 13	Case 14	Case 15	Case 16	Case 17
		Annual Average 43 °F 50% CT Load Unfired	Annual Average 43 °F 25% CT Load Unfired	Summer 94 °F 75% CT Load Unfired	Summer 94 °F 50% CT Load Unfired	Summer 94 °F 25% CT Load Unfired
Number of Combustion Turbines		1	1	1	1	1
Maximum Annual Hours of Operation	hours	8,760	8,760	8,760	8,760	8,760
SITE CONDITIONS						
Ambient Temperature	°F	43	43	94	94	94
Relative Humidity	%	64	64	38	38	38
Site Elevation	feet	1,850	1,850	1,850	1,850	1,850
Site Pressure	psia	13.76	13.76	13.76	13.76	13.76
FACILITY CONDITIONS						
CT Fuel Type		Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CT Model		GE-PG7241(FA)	GE-PG7241(FA)	GE-PG7241(FA)	GE-PG7241(FA)	GE-PG7241(FA)
CT Load		50%	25%	75%	50%	25%
CT Gross Power Output (per CT)	kW	83,100	41,500	105,200	70,100	35,100
CT Heat Consumption (LHV)	MMBtu/hr (LHV)	1,003.0	691.0	1,127.0	897.0	635.0
CT Heat Consumption (HHV)	MBtu/hr	1,113.3	767.0	1,250.9	995.6	704.8
CT Fuel Flow Rate	lb/hr	48,951	33,724	55,002	43,777	30,991
CT Fuel Flow Rate	Mscf/hr	1.11	0.77	1.25	0.99	0.70
CT Exhaust Gas Flow Rate	lb/hr	2,285,000	1,826,000	2,567,000	2,162,000	1,750,000
CT Exhaust Gas Temperature	°F	1,200	1,149	1,191	1,200	1,187
DB Heat Consumption (LHV)	MBtu/hr	0.0	0.0	0.0	0.0	0.0
DB Heat Consumption (HHV)	MBtu/hr	0.0	0.0	0.0	0.0	0.0
DB Fuel Flow Rate	lb/hr	0	0	0	0	0
DB Fuel Flow Rate	Mscf/hr	0.00	0.00	0.00	0.00	0.00
Gross Steam Turbine Output	kW	61,058	45,227	66,159	55,560	42,448
Total Gross Plant Electrical Output	kW	144,158	86,727	171,359	125,660	77,548
Total Auxiliry Power	kW	4,208	2,752	8,869	7,995	7,076
Net Plant Electrical Output	kW	139,950	83,975	162,490	117,665	70,472
Net Plant Electrical Heat Rate, LHV	Btu/kWh$_{net}$ (LHV)	7,167	8,229	6,936	7,623	9,011
NATURAL GAS ANALYSIS						
Fuel LHV	Btu/lb	20,490	20,490	20,490	20,490	20,490
Fuel HHV	Btu/lb	22,743	22,743	22,743	22,743	22,743
Fuel LHV	Btu/ft^3	902.9	902.9	902.9	902.9	902.9
Fuel HHV	Btu/ft^3	1,002.1	1,002.1	1,002.1	1,002.1	1,002.1
HHV/LHV Ratio		1.11	1.11	1.11	1.11	1.11
Total Sulfur, S (Note 1)	grains/100 ft^3	0.50	0.50	0.50	0.50	0.50

Table B-3: Part Load Cases - continued

		PART LOAD CASES Case 13	Case 14	Case 15	Case 16	Case 17
		Annual Average 43 °F 50% CT Load Unfired	Annual Average 43 °F 25% CT Load Unfired	Summer 94 °F 75% CT Load Unfired	Summer 94 °F 50% CT Load Unfired	Summer 94 °F 25% CT Load Unfired
COMBUSTION TURBINE EXHAUST ANALYSIS						
Argon, Ar	% vol	0.89	0.90	0.89	0.88	0.89
Nitrogen, N_2	% vol	74.81	75.20	73.63	73.81	74.09
Oxygen, O_2	% vol	12.87	14.01	12.52	13.03	13.85
Carbon Dioxide, CO_2	% vol	3.67	3.15	3.68	3.45	3.07
Water, H_2O	% vol	7.76	6.74	9.28	8.83	8.10
Total		*100.0*	*100.0*	*100.0*	*100.0*	*100.0*
Molecular weight	lb/lbmol	28.44	28.51	28.28	28.31	28.35
COMBUSTION TURBINE EMISSIONS (per CT)						
NO_X	ppmvd @ 15% O_2	9.0	9.0	9.0	9.0	9.0
NO_X	ppmvd	10.6	9.0	10.8	10.1	8.9
NO_X as NO_2	lb/hr	36.1	24.7	40.9	32.4	23.2
CO	ppmvd @ 15% O_2	7.6	9.0	7.5	8.0	9.1
CO	ppmvd	9.0	9.0	9.0	9.0	9.0
CO	lb/hr	18.7	15.1	20.8	17.6	14.3
VOC (non-methane, non-ethane) (Note 2	ppmvd @ 15% O_2	1.29	1.51	1.28	1.37	1.54
VOC (non-methane, non-ethane)	ppmvd	1.52	1.50	1.54	1.54	1.52
VOC (non-methane, non-ethane)	ppmvw	1.40	1.40	1.40	1.40	1.40
VOC as CH_4	lb/hr	1.80	1.44	2.04	1.72	1.39
SO_2	ppmvd @ 15% O_2	0.28	0.28	0.28	0.29	0.28
SO_2	ppmvd	0.33	0.28	0.34	0.32	0.28
SO_2	lb/hr	1.59	1.09	1.78	1.42	1.00
SO_3 Oxidation (Note 3)	%	8%	8%	8%	8%	8%
SO_3	ppmvd @ 15% O_2	0.022	0.022	0.022	0.023	0.022
SO_3	ppmvd	0.026	0.022	0.026	0.026	0.022
SO_3	lb/hr	0.154	0.105	0.171	0.145	0.100
Formaldehyde, HCHO (AP-42 Table 3.1-3)	lb/MBtu (HHV)	7.1E-04	7.1E-04	7.1E-04	7.1E-04	7.1E-04
Formaldehyde, HCHO	lb/hr	0.79	0.54	0.89	0.71	0.50
PM10						
PM10-filterable (Note 4)	lb/MBtu (HHV)	0.00475	0.00475	0.00475	0.00475	0.00475
PM10-filterable	lb/hr	5.3	3.6	5.9	4.7	3.3
PM10-condensible (Note 4, 9)	lb/MBtu (HHV)	0.0047	0.0047	0.0047	0.0047	0.0047
PM10-condensible (Note 4, 9)	lb/hr	5.2	3.6	5.9	4.7	3.3

Table B-3: Part Load Cases - continued

		PART LOAD CASES				
		Case 13	Case 14	Case 15	Case 16	Case 17
		Annual Average 43 °F 50% CT Load Unfired	Annual Average 43 °F 25% CT Load Unfired	Summer 94 °F 75% CT Load Unfired	Summer 94 °F 50% CT Load Unfired	Summer 94 °F 25% CT Load Unfired
DUCT BURNER EMISSIONS (per CT/HRSG)						
DB Heat Consumption (HHV)	MBtu/hr	0.0	0.0	0.0	0.0	0.0
DB Heat Consumption (HHV)	Mscf/hr	0.0	0.0	0.0	0.0	0.0
NO_X	lb/MBtu, HHV	0.050	0.050	0.050	0.050	0.050
NO_X	lb/hr	0.0	0.0	0.0	0.0	0.0
CO	lb/MBtu, HHV	0.050	0.050	0.050	0.050	0.050
CO	lb/hr	0.0	0.0	0.0	0.0	0.0
VOC (non-methane, non-ethane) (Note 2)	lb/MBtu, HHV	0.020	0.020	0.020	0.020	0.020
VOC as CH_4	lb/hr	0.00	0.00	0.00	0.00	0.00
SO_2	lb/hr	0.00	0.00	0.00	0.00	0.00
SO_3 Oxidation	%	8%	8%	8%	8%	8%
SO_3	lb/hr	0.000	0.000	0.000	0.000	0.000
Formaldehyde, HCHO (AP-42 Table 1.4-3)	lb/Mscf	7.50E-02	7.50E-02	7.50E-02	7.50E-02	7.50E-02
Formaldehyde, HCHO	lb/hr	0.000	0.000	0.000	0.000	0.000
PM10						
PM10-filterable (Note 4)	lb/MBtu, HHV	0.005	0.005	0.005	0.005	0.005
PM10-filterable	lb/hr	0.0	0.0	0.0	0.0	0.0
PM10-condensible (AP-42, Table 1.4-2)	lb/Mscf	5.7	5.7	5.7	5.7	5.7
PM10-condensible	lb/hr	0.0	0.0	0.0	0.0	0.0
POST DUCT BURNER EMISSIONS (per CT/HRSG)						
NO_X	ppmvd @ 15% O_2	9.0	9.0	9.0	9.0	9.0
NO_X	ppmvd	10.6	9.0	10.8	10.1	8.9
NO_X as NO_2	lb/hr	36.1	24.7	40.9	32.4	23.2
CO	ppmvd @ 15% O_2	7.6	9.0	7.5	8.0	9.1
CO	ppmvd	9.0	9.0	9.0	9.0	9.0
CO	lb/hr	18.7	15.1	20.8	17.6	14.3
VOC (non-methane, non-ethane) (Note 2)	ppmvd @ 15% O_2	1.28	1.51	1.28	1.37	1.55
VOC (non-methane, non-ethane)	ppmvd	1.51	1.50	1.54	1.54	1.53
VOC (non-methane, non-ethane)	ppmvw	1.40	1.40	1.40	1.40	1.40
VOC as CH_4	lb/hr	1.80	1.44	2.04	1.72	1.39

Table B-3: Part Load Cases - continued

		PART LOAD CASES				
		Case 13	Case 14	Case 15	Case 16	Case 17
		Annual Average 43 °F 50% CT Load Unfired	Annual Average 43 °F 25% CT Load Unfired	Summer 94 °F 75% CT Load Unfired	Summer 94 °F 50% CT Load Unfired	Summer 94 °F 25% CT Load Unfired
SO_2	ppmvd @ 15% O_2	0.28	0.28	0.28	0.29	0.28
SO_2	ppmvd	0.33	0.28	0.34	0.32	0.28
SO_2	lb/hr	1.59	1.09	1.78	1.42	1.00
SO_3	ppmvd @ 15% O_2	0.022	0.022	0.022	0.023	0.022
SO_3	ppmvd	0.026	0.022	0.026	0.026	0.022
SO_3	lb/hr	0.15	0.11	0.17	0.15	0.10
Formaldehyde, HCHO	lb/hr	0.790	0.540	0.890	0.710	0.500
PM10						
PM10-filterable	lb/hr	5.3	3.6	5.9	4.7	3.3
PM10-condensible	lb/hr	5.2	3.6	5.9	4.7	3.3
POST SCR EMISSIONS (per CT/HRSG)						
Are NOx Emissions Controlled with SCR?	Yes/No	Yes	Yes	Yes	Yes	Yes
If SCR, Controlled NOx Emission Rate	ppmvd @ 15% O_2	3.5	3.5	3.5	3.5	3.5
If SCR, Maximum NH_3 Slip	ppmvd @ 15% O_2	5.0	5.0	5.0	5.0	5.0
Hours of Operation (Note 5)	hours/year	8,760	8,760	8,760	8,760	8,760
NO_X	ppmvd @ 15% O_2	3.5	3.5	3.5	3.5	3.5
NO_X Removal Efficiency	% decrease	60.0%	60.0%	60.0%	60.0%	60.0%
NO_X	ppmvd	4.1	3.5	4.2	3.9	3.5
NO_X	lb/hr	14.0	9.6	15.9	12.5	9.1
NO_X	lb/mmBtu (HHV)	0.013	0.013	0.013	0.013	0.013
NO_X	ton/yr	61.3	42.0	69.6	54.8	39.9
NH_3	ppmvd @ 15% O_2	5.0	5.0	5.0	5.0	5.0
NH_3	ppmvd	5.9	5.0	6.0	5.6	4.9
NH_3	lb/hr	7.4	5.1	8.4	6.6	4.7
NH_3	lbmol/hr	0.43	0.30	0.49	0.39	0.28
NH_3	ton/yr	32.4	22.3	36.8	28.9	20.6
CO	ppmvd @ 15% O_2	7.6	9.0	7.5	8.0	9.1
CO	ppmvd	8.9	9.0	9.0	9.0	9.0
CO	lb/hr	18.5	15.1	20.8	17.6	14.3
CO	lb/mmBtu (HHV)	0.017	0.020	0.017	0.018	0.020
CO	ton/yr	81.0	66.1	91.1	77.1	62.6

Table B-3: Part Load Cases - continued

		PART LOAD CASES				
		Case 13	Case 14	Case 15	Case 16	Case 17
		Annual Average 43 °F 50% CT Load Unfired	Annual Average 43 °F 25% CT Load Unfired	Summer 94 °F 75% CT Load Unfired	Summer 94 °F 50% CT Load Unfired	Summer 94 °F 25% CT Load Unfired
VOC (non-methane, non-ethane) (Note 2)	ppmvd @ 15% O_2	1.28	1.51	1.28	1.37	1.55
VOC (non-methane, non-ethane)	ppmvd	1.51	1.50	1.54	1.53	1.53
VOC as CH_4	lb/hr	1.80	1.44	2.03	1.71	1.39
VOC as CH_4	lb/mmBtu (HHV)	0.0016	0.0019	0.0016	0.0017	0.0020
VOC as CH_4	ton/yr	7.9	6.3	8.9	7.5	6.1
SO_2	ppmvd @ 15% O_2	0.28	0.28	0.28	0.29	0.28
SO_2	ppmvd	0.33	0.28	0.34	0.32	0.28
SO_2	lb/hr	1.59	1.09	1.78	1.42	1.00
SO_2	lb/mmBtu (HHV)	0.0014	0.0014	0.0014	0.0014	0.0014
SO_2	ton/yr	7.0	4.8	7.8	6.2	4.4
SO_3 Oxidation across SCR (Note 6)	% increase	4%	4%	4%	4%	4%
SO_3 Oxidation across SCR	lb/hr	0.079	0.054	0.089	0.071	0.050
SO_3	ppmvd @ 15% O_2	0.033	0.033	0.032	0.035	0.033
SO_3	ppmvd	0.039	0.033	0.039	0.039	0.033
SO_3	lb/hr	0.23	0.16	0.26	0.22	0.15
SO_3	lbmol/hr	2.87E-03	2.00E-03	3.25E-03	2.75E-03	1.87E-03
H_2SO_4, Sulfuric Acid Mist	lb/hr	0.28	0.20	0.32	0.27	0.18
H_2SO_4, Sulfuric Acid Mist	ton/yr	1.23	0.88	1.40	1.18	0.79
$(NH_4)_2SO_4$, Ammonium Sulfate (Note 7, 8)	lb/hr	0.38	0.26	0.43	0.36	0.25
$(NH_4)_2SO_4$, Ammonium Sulfate (Note 7, 8)	ton/yr	1.66	1.14	1.88	1.58	1.10
Formaldehyde, HCHO	lb/hr	0.79	0.54	0.89	0.71	0.50
Formaldehyde, HCHO	ton/yr	3.46	2.37	3.90	3.11	2.19
Particulate Matter Emissions						
PM10-filterable	lb/hr	5.3	3.6	5.9	4.7	3.3
PM10-filterable	lb/mmBtu (HHV)	0.0048	0.0047	0.0047	0.0047	0.0047
PM10-filterable	ton/yr	23.2	15.8	25.8	20.6	14.5
PM10-condensible (Note 10)	lb/hr	5.6	3.9	6.3	5.1	3.6
PM10-condensible (Note 10)	ton/yr	24.5	17.1	27.6	22.3	15.8
Total PM10 (filterable + condensible) (Note 11)	lb/hr	10.9	7.5	12.2	9.8	6.9
Total PM10 (filterable + condensible) (Note 11)	lb/mmBtu (HHV)	0.0098	0.0098	0.0098	0.0098	0.0098
Total PM10	ton/yr	47.7	32.9	53.4	42.9	30.2
CO_2	lb/hr	129,752	88,792	147,012	115,967	83,393
CO_2	ton/yr	568,313	388,910	643,911	507,934	365,260
Aqueous Ammonia (per CT/HRSG)						
Purity (Note 13)	%	19.5	19.5	19.5	19.5	19.5
Consumption	lb/hr	79.9	54.8	90.5	71.6	50.9
Stack Conditions (per CT/HRSG)						
Flow	lb/hr	2,285,080	1,826,055	2,567,091	2,162,072	1,750,051

Table B-4
Deer Creek CT/HRSG Emission Calculations
Emission Summaries

Emissions Summary

Case		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
		Winter Extreme Case	Winter Extreme Case	Annual Average	Annual Average	Summer	Summer
Ambient Temp / Load		-41 oF	-41 oF	43 oF	43 oF	94 oF	94 oF
		Base Load	Base Load	Base Load	Base Load	Base Load	Base Load
Duct Firing (Fired / Unfired)		Unfired	Duct Firing	Unfired	Duct Firing	Unfired	Duct Firing
Annual Hours of Operation (for permitting)	hours	8,760	8,760	8,760	8,760	8,760	8,760
CT Power Output (per CT)	kW	184,557	184,557	166,178	166,178	150,600	150,600
CT Heat Consumption (per CT LHV)	mmBtu/hr	1,713.0	1,713.0	1,541.0	1,541.0	1,434.0	1,434.0
DB Heat Consumption (per HRSG LHV)	mmBtu/hr	0.0	297.9	0.0	511.1	0.0	610.4
Total Heat Input to CTs + HRSGs	mmBtu/hr	**1,713.0**	**2,010.9**	**1,541.0**	**2,052.1**	**1,434.0**	**2,044.4**
Gross Steam Turbine Output	kW	85,326	122,116	83,505	142,723	79,936	152,860
Total Gross Electrical Output	kW	**269,883**	**306,673**	**249,683**	**308,901**	**230,536**	**303,460**
Auxiliary Power	kW	**5,390**	**6,393**	**6,507**	**8,528**	**10,001**	**10,884**
Net Plant Electrical Output	kw	**264,493**	**300,280**	**243,176**	**300,373**	**220,535**	**292,576**
Net Plant Electrical Heat Rate, LHV	Btu/kWh_{net} (LHV)	**6,477**	**6,697**	**6,337**	**6,832**	**6,502**	**6,988**
Emissions (per CT/HRSG)		lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
	NO_X	24.5	29.0	21.8	29.2	20.4	29.4
	CO	32.0	48.7	28.5	57.2	26.0	59.9
	VOC	3.07	9.68	2.74	14.13	2.55	16.10
	SO_2	2.71	3.18	2.44	3.25	2.27	3.24
	$PM_{10}/PM_{2.5}$ (filterable)	9.0	10.7	8.1	10.9	7.6	11.0
	Total $PM_{10}/PM_{2.5}$	18.6	22.3	16.7	22.9	15.7	23.2
	Sulfuric Acid Mist	0.49	0.58	0.45	0.60	0.42	0.59
Stack Diameter (Note 13)	ft	19.0	19.0	19.0	19.0	19.0	19.0
Flow (total)	lb/hr	3,898,140	3,912,713	3,489,126	3,514,130	3,231,119	3,260,979
Velocity	ft/sec	69.0	69.4	61.9	62.6	57.8	58.7
Temperature (Note 14)	°F	200	200	200	200	200	200
Flow (total)	acfm	1,173,115	1,180,657	1,052,484	1,065,424	982,517	997,971
Flow (total)	scfm	878,480	884,127	788,146	797,836	735,752	747,324
Flow (total)	dscfm	814,087	808,711	725,567	716,344	662,177	651,161

Table B-4: Deer Creek CT/HRSG Emission Summaries, continued

Emissions Summary

Case		Case 7	Case 8		Case 12	Case 13	Case 14	Case 15
		Record Summer	Record Summer		Annual Average	Annual Average	Annual Average	Summer
Ambient Temp / Load		109 oF	109 oF		43 oF	43 oF	43 oF	94 oF
		Base Load	Base Load		75% CT Load	50% CT Load	25% CT Load	75% CT Load
Duct Firing (Fired / Unfired)		Unfired	Duct Firing		Unfired	Unfired	Unfired	Unfired
Annual Hours of Operation (for permitting)	hours	8,760	8,760		8,760	8,760	8,760	8,760
CT Power Output (per CT)	kW	147,900	147,900		124,600	83,100	41,500	105,200
CT Heat Consumption (per CT LHV)	mmBtu/hr	1,416.0	1,416.0		1,252.0	1,003.0	691.0	1,127.0
DB Heat Consumption (per HRSG LHV)	mmBtu/hr	0.0	615.2		0.0	0.0	0.0	0.0
Total Heat Input to CTs + HRSGs	mmBtu/hr	**1,416.0**	**2,031.2**		**1,252.0**	**1,003.0**	**691.0**	**1,127.0**
Gross Steam Turbine Output	kW	74,632	146,127		71,819	61,058	45,227	66,159
Total Gross Electrical Output	kW	222,532	294,027		**196,419**	**144,158**	86,727	**171,359**
Auxiliary Power	kW	**10,002**	**10,904**		**5,349**	**4,208**	2,752	**8,869**
Net Plant Electrical Output	kw	**212,530**	**283,123**		**191,070**	**139,950**	**83,975**	**162,490**
Net Plant Electrical Heat Rate, LHV	Btu/kWh_{net} (LHV)	**6,663**	7,174		**6,553**	**7,167**	**8,229**	**6,936**
Emissions (per CT/HRSG)		lb/hr	lb/hr		lb/hr	lb/hr	lb/hr	lb/hr
	NO_X	20.1	29.0		17.8	14.0	9.6	15.9
	CO	25.6	59.6		22.7	18.5	15.1	20.8
	VOC	2.54	16.20		2.19	1.80	1.44	2.03
	SO_2	2.24	3.21		1.98	1.59	1.09	1.78
	$PM_{10}/PM_{2.5}$ (filterable)	7.5	10.9		6.6	5.3	3.6	5.9
	Total $PM_{10}/PM_{2.5}$	15.4	23.0		13.6	10.9	7.5	12.2
	Sulfuric Acid Mist	0.40	0.59	##	0.36	0.28	0.20	0.32
Stack Diameter (Note 13)	ft	19.0	19.0		19.0	19.0	19.0	19.0
Flow (total)	lb/hr	3,190,115	3,220,211		2,780,100	2,285,080	1,826,055	2,567,091
Velocity	ft/sec	57.1	58.0		49.3	40.5	32.3	45.8
Temperature (Note 14)	°F	200	200		200	200	200	200
Flow (total)	acfm	970,902	986,477		838,744	689,055	549,374	778,592
Flow (total)	scfm	727,054	738,717		628,088	515,994	411,396	583,044
Flow (total)	dscfm	652,749	641,647		577,778	475,953	383,668	528,938

Table B-4: Deer Creek CT/HRSG Emission Summaries, continued

Emissions Summary

Case		Case 16	Case 17
		Summer	Summer
Ambient Temp / Load		94 oF	94 oF
		50% CT Load	25% CT Load
Duct Firing (Fired / Unfired)		Unfired	Unfired
Annual Hours of Operation (for permitting)	hours	8,760	8,760
CT Power Output (per CT)	kW	70,100	35,100
CT Heat Consumption (per CT LHV)	mmBtu/hr	897.0	635.0
DB Heat Consumption (per HRSG LHV)	mmBtu/hr	0.0	0.0
Total Heat Input to CTs + HRSGs	mmBtu/hr	**897.0**	**635.0**
Gross Steam Turbine Output	kW	55,560	42,448
Total Gross Electrical Output	kW	**125,660**	**77,548**
Auxiliary Power	kW	**7,995**	**7,076**
Net Plant Electrical Output	kw	**117,665**	**70,472**
Net Plant Electrical Heat Rate, LHV	Btu/kWh$_{net}$ (LHV)	**7,623**	**9,011**
Emissions (per CT/HRSG)		lb/hr	lb/hr
	NO_X	12.5	9.1
	CO	17.6	14.3
	VOC	1.71	1.39
	SO_2	1.42	1.00
	$PM_{10}/PM_{2.5}$ (filterable)	4.7	3.3
	Total $PM_{10}/PM_{2.5}$	9.8	6.9
	Sulfuric Acid Mist	0.27	0.18
Stack Diameter (Note 13)	ft	19.0	19.0
Flow (total)	lb/hr	2,162,072	1,750,051
Velocity	ft/sec	38.5	31.1
Temperature (Note 14)	°F	200	200
Flow (total)	acfm	655,118	529,412
Flow (total)	scfm	490,581	396,447
Flow (total)	dscfm	447,263	364,335

Table B-5
Deer Creek Station
Emission Calculations
Auxiliary Combustion Sources: Cases and Assumptions

Project:	**Basin Electric Power Cooperative**
	Deer Creek Generating Station

Auxiliary Combustion Sources

Emergency Diesel Generator			
Generator Rating:	2,500	kVA	
Generator Output:	2,000	kW	
Fuel:	diesel		
Heating Value of Fuel:	141,000	Btu/gal	DOE Office of Energy Efficiency & Renewable Energy
Assumed Generator Efficiency:	91.75%	%	Engine efficiencies were estimated from typical vendor data.
Assumed Diesel Engine Efficiency:	33%	%	Engine efficiencies were estimated from typical vendor data.
Hours of Operation:	150		

Diesel Fired Fire Water Pump			
Diesel Engine Output:	577	hp	Engined sized for 3,000 gpm plus margin.
Fuel:	diesel		
Fuel Heating Value:	141,000	Btu/gal	DOE Office of Energy Efficiency & Renewable Energy
Assumed Diesel Engine Efficiency:	33%	%	Engine efficiencies were estimated from typical vendor data.
Hours of Operation:	150		

Inlet Air Heater		
Fuel:	natural gas	
Fuel Heating Value:	1,020	Btu/scf
Heat Duty:	19.0	mmBtu/hr
Fluid Heated:	56% Water / 44% Ethylene Glycol	
Fluid Flow:	792,300	lb/hr
Gross Heater Release:	25.0	mmBtu/hr
Number of Burners:	1	
Excess Air:	10%	%
Moisture in Air:	0.015	lb H_2O / lb dry air
Exit Gas Temperature:	300	°F
Hours of Operation:	150	hours/year

Table B-6
Deer Creek Station: Emergency Diesel Generator
Criteria Pollutant Emissions

Generator Output:	**2,000**	kW
Assumed generator efficiency:	91.8%	(Note 1)
Generator Input:	2,180	kW
Diesel Engine Output:	**2,923**	hp
Assumed Diesel engine efficiency:	33%	(Note 1)
Diesel Engine Input:	8,858	hp
Diesel Engine Input:	**22.53**	mmBtu/hr
Heating Value No. 2 Fuel Oil:	141,000	Btu/gal
Maximum Fuel Firing Rate:	159.8	gal/hr
Maximum Fuel Firing Rate:	1,141	lb/hr
laximum Annual Hours of Operation:	**150**	hours/year

Pollutant	Emission Factor	Units	Source (Note 2)	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
CO	2.61	g/hp-hr (output)	CI ICE NSPS Standard	16.8	1.3
NMHC + NOx	4.77	g/hp-hr (output)	CI ICE NSPS Standard	30.7	2.3
NOx	4.48	g/hp-hr (output)	Calculated as: (NMHC+NOx) - VOC	28.9	2.2
PM	0.15	g/hp-hr (output)	CI ICE NSPS Standard	0.97	0.07
PM10 (Note 1)	0.12	g/hp-hr (output)	Calculate: AP-42 Table 3.4-2	0.77	0.06
VOC	0.082	lb/mmBtu Heat Input	AP-42 Table 3.4-1 (10/96)	1.85	0.14
SO_2	0.051	lb/mmBtu Heat Input	Calculated based on fuel sulfur content	1.15	0.09
H_2SO_4	0.004	lb/mmBtu Heat Input	Calculated assuming 5% SO_2 to SO_3 conversion	0.088	0.007

Note 1: PM10 was calculated as 80% of total PM based on particle-sizing data in AP-42 Table 3.4-2.

Exhaust Gas Parameters (approximate)	
Gas Volume (scfm)	4,629
Gas Volume (acfm)	12,881

STACK DATA (preliminary) - Note 3		
Height	40	ft. agl (preliminary estimate)
Diameter	17.1	inches
Exhaust Flow	12,881	acfm
Exhaust Temperature	987	°F (data sheet for recently purchased EDG)
Exhaust Velocity	135	ft/sec. (data sheet for recently purchased EDG)

NOTES:

1. Efficiencies for the engine are estimated from typical vendor data.
   Emission factors for NOx, CO, and PM10 were based on the compression ignition internal
2. combustion engine (CI ICE) NSPS (71 FR 39152, July 11, 2006).
   The VOC emission factor was taken from AP-42 Table 3.4-1, Gaseous Emission Factors for Large Stationary Diesel Engines.
   The SO_2 emission factor was calculated based on a maximum fuel sulfur content of 0.05%.
   The H_2SO_4 emission factor was calculated assuming 5% SO_2 to SO_3 conversion during
   The exhaust gas velocity was set to 135 ft/sec, and the stack diameter was sized to accommodate
3. the exhaust flow accordingly.
   The stack height will be determined based on vendor input and emissions modeling to avoid the downwash cavity.

Table B-7
Deer Creek Station: Emergency Diesel Generator
Non-Criteria Pollutant Emissions

Diesel Engine Output	2,923	hp
Maximum Heat Input	22.53	mmBtu/hr
Maximum Annual Hours	150	hours/year

PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (AP-42 Table 3.4-4) (Note 1)

Pollutant	Emission Factor lb/mmBtu	Emission Factor Rating	Source	HAP (yes/no)	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Naphthalene	1.30E-04	E	AP-42 (10/96) Table 3.4-4	yes	2.93E-03	2.20E-04
Acenaphthylene	9.23E-06	E	AP-42 (10/96) Table 3.4-4	no	2.08E-04	1.56E-05
Acenaphthene	4.68E-06	E	AP-42 (10/96) Table 3.4-4	no	1.05E-04	7.91E-06
Fluorene	1.28E-05	E	AP-42 (10/96) Table 3.4-4	no	2.88E-04	2.16E-05
Phenanthrene	4.08E-05	E	AP-42 (10/96) Table 3.4-4	no	9.19E-04	6.89E-05
Anthracene	1.23E-06	E	AP-42 (10/96) Table 3.4-4	no	2.77E-05	2.08E-06
Fluoranthene	4.03E-06	E	AP-42 (10/96) Table 3.4-4	no	9.08E-05	6.81E-06
Pyrene	3.71E-06	E	AP-42 (10/96) Table 3.4-4	no	8.36E-05	6.27E-06
Benzo(a)anthracene	6.22E-07	E	AP-42 (10/96) Table 3.4-4	no	1.40E-05	1.05E-06
Chrysene	1.53E-06	E	AP-42 (10/96) Table 3.4-4	no	3.45E-05	2.59E-06
Benzo(b)fluoranthene	1.11E-06	E	AP-42 (10/96) Table 3.4-4	no	2.50E-05	1.88E-06
Benzo(k)fluoranthene*	2.18E-07	E	AP-42 (10/96) Table 3.4-4	no	4.91E-06	3.68E-07
Benzo(a)pyrene*	2.57E-07	E	AP-42 (10/96) Table 3.4-4	no	5.79E-06	4.34E-07
Indeno(1,2,3-cd)pyrene*	4.14E-07	E	AP-42 (10/96) Table 3.4-4	no	9.33E-06	7.00E-07
Dibenz(a,h)anthracene*	3.46E-07	E	AP-42 (10/96) Table 3.4-4	no	7.80E-06	5.85E-07
Benzo(g,h,i)perylene*	5.56E-07	E	AP-42 (10/96) Table 3.4-4	no	1.25E-05	9.40E-07
Total PAH					**0.0048**	**0.0004**
Total PAH HAP Emissions					**0.0029**	**0.0002**

Speciated Organic Emission Factors for Large Uncontrolled Stationary Diesel Engines (AP-42 Table 3.4-3) (Note 2)

Pollutant	Emission Factor lb/mmBtu	Emission Factor Rating	Source	HAP (yes/no)	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Benzene	7.76E-04	lb/mmBtu	AP-42 (10/96) Table 3.4-3	yes	1.75E-02	1.31E-03
Toluene	2.81E-04	lb/mmBtu	AP-42 (10/96) Table 3.4-3	yes	6.33E-03	4.75E-04
Xylenes	1.93E-04	lb/mmBtu	AP-42 (10/96) Table 3.4-3	yes	4.35E-03	3.26E-04
Formaldehyde	7.89E-05	lb/mmBtu	AP-42 (10/96) Table 3.4-3	yes	1.78E-03	1.33E-04
Acetaldehyde	2.52E-05	lb/mmBtu	AP-42 (10/96) Table 3.4-3	yes	5.68E-04	4.26E-05
Acrolein	7.88E-06	lb/mmBtu	AP-42 (10/96) Table 3.4-3	yes	1.78E-04	1.33E-05
Speciated Organic HAP Emissions					**0.031**	**0.002**
Total HAP Emissions					**0.034**	**0.0025**

* Emission factor in AP-42 is less than the emission rate shown (i.e., <X lb/mmBtu).

Notes:

1. Table 3.4-4 emission factors were developed based on 1 uncontrolled diesel engine, SCC 2-02-004-01.
2. Table 3.4-3 emission factors were developed based on 1 uncontrolled diesel engine, SCC 2-02-004-01.

Table B-8
Deer Creek Station: Diesel-Fired Fire Water Pump
Criteria Pollutant Emissions

Diesel Engine Output:	**577**	hp (Note 1)
Assumed Diesel engine efficiency:	**33%**	(Note 2)
Diesel Engine Input:	1,748	hp
Diesel Engine Input:	**4.45**	mmBtu/hr
Heating Value for No. 2 Fuel Oil:	**141,000**	Btu/gal
Maximum Fuel Firing Rate:	**31.6**	gal/hr
Maximum Fuel Firing Rate:	**231**	lb/hr
Maximum Annual Hours of Operation:	**150**	hours/year

Pollutant	Emission Factor	Units	Source (Note 3)	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
CO	2.6	g/hp-hr (output)	CI ICE NSPS Standard	3.31	0.25
NMHC + NO_x	3.0	g/hp-hr (output)	CI ICE NSPS Standard	3.82	0.29
NOx	1.9	g/hp-hr (output)	Calculated as: (NMHC+NOx) - VOC	2.39	0.18
PM/PM10	0.15	g/hp-hr (output)	CI ICE NSPS Standard	0.19	0.014
VOC	2.47E-03	lb/hp-hr (output)	AP-42 (10/96) Table 3.3-1 (Note 4)	1.43	0.11
SO_2	0.052	lb/mmBtu Heat Input	Calculated based on fuel sulfur content	0.23	0.02
H_2SO_4	0.004	lb/mmBtu Heat Input	Calculated assuming 5% SO_2 to SO_3	0.018	0.001

Exhaust Gas Parameters (approximate)	
Gas Volume (scfm)	932
Gas Volume (acfm)	2,339

STACK DATA (preliminary) - Note 4		
Height	40	ft. agl (preliminary estimate)
Diameter	7.28	inches
Exhaust Flow	2,339	acfm
Exhaust Temperature	845	°F (data sheet for recently purchased FWP)
Exhaust Velocity	135	ft/sec. (data sheet for recently purchased FWP)

NOTES:

1. Engine output based on recent project which required a 360 hp engine for 2500 gpm flow.
2. Engine efficiencies were estimated from typical vendor data.
3. Emission factors for NOx, CO, and PM10 were based on the compression ignition internal combustion engine (CI ICE) NSPS (71 FR 39152, July 11, 2006).
   The VOC emission factor was taken from AP-42 Table 3.3-1, Emission Factors for Gasoline and Diesel Industrial Engines.
   The SO_2 emission factor was calculated based on a maximum fuel sulfur content of 0.05%.
   The H_2SO_4 emission factor was calculated assuming 5% SO_2 to SO_3 conversion during combustion.
4. The exhaust gas velocity was set to 135 ft/sec, and the stack diameter was sized to accommodate the exhaust flow accordingly.
   The stack height will be determined based on vendor input and emissions modeling to avoid the downwash cavity.

Table B-9
Deer Creek Station: Diesel-Fired Fire Water Pump
Non-Criteria Pollutant Emissions

Diesel Engine Output	577	hp
Maximum Heat Input	4.45	mmBtu/hr
Maximum Annual Hours	150	hours/year

Pollutant	Emission Factor lb/mmBtu	Emission Factor Rating	Source (Note 1)	HAP (yes/no)	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Benzene	9.33E-04	E	AP-42 (10/96) Table 3.3-2	yes	4.15E-03	3.11E-04
Toluene	4.09E-04	E	AP-42 (10/96) Table 3.3-2	yes	1.82E-03	1.37E-04
Xylenes	2.85E-04	E	AP-42 (10/96) Table 3.3-2	yes	1.27E-03	9.51E-05
Propylene	2.58E-03	E	AP-42 (10/96) Table 3.3-2	yes	1.15E-02	8.61E-04
1,3-Butidiene*	3.91E-05	E	AP-42 (10/96) Table 3.3-2	yes	1.74E-04	1.30E-05
Formaldehyde	1.18E-03	E	AP-42 (10/96) Table 3.3-2	yes	5.25E-03	3.94E-04
Acetaldehyde	7.67E-04	E	AP-42 (10/96) Table 3.3-2	yes	3.41E-03	2.56E-04
Acrolein*	9.25E-05	E	AP-42 (10/96) Table 3.3-2	yes	4.12E-04	3.09E-05
PAHs						
Naphthalene	8.48E-05	E	AP-42 (10/96) Table 3.3-2	yes	3.77E-04	2.83E-05
Acenaphthylene*	5.06E-06	E	AP-42 (10/96) Table 3.3-2	no	2.25E-05	1.69E-06
Acenaphthene*	1.42E-06	E	AP-42 (10/96) Table 3.3-2	no	6.32E-06	4.74E-07
Fluorene	2.92E-05	E	AP-42 (10/96) Table 3.3-2	no	1.30E-04	9.75E-06
Phenanthrene	2.94E-05	E	AP-42 (10/96) Table 3.3-2	no	1.31E-04	9.81E-06
Anthracene	1.87E-06	E	AP-42 (10/96) Table 3.3-2	no	8.32E-06	6.24E-07
Fluoranthene	7.61E-06	E	AP-42 (10/96) Table 3.3-2	no	3.39E-05	2.54E-06
Pyrene	4.78E-06	E	AP-42 (10/96) Table 3.3-2	no	2.13E-05	1.60E-06
Benzo(a)anthracene	1.68E-06	E	AP-42 (10/96) Table 3.3-2	no	7.48E-06	5.61E-07
Chrysene	3.53E-07	E	AP-42 (10/96) Table 3.3-2	no	1.57E-06	1.18E-07
Benzo(b)fluoranthene*	9.91E-08	E	AP-42 (10/96) Table 3.3-2	no	4.41E-07	3.31E-08
Benzo(k)fluoranthene*	1.55E-07	E	AP-42 (10/96) Table 3.3-2	no	6.90E-07	5.17E-08
Benzo(a)pyrene*	1.88E-07	E	AP-42 (10/96) Table 3.3-2	no	8.37E-07	6.27E-08
Indeno(1,2,3-cd)pyrene*	3.75E-07	E	AP-42 (10/96) Table 3.3-2	no	1.67E-06	1.25E-07
Dibenz(a,h)anthracene*	5.83E-07	E	AP-42 (10/96) Table 3.3-2	no	2.59E-06	1.95E-07
Benzo(g,h,l)perylene*	4.89E-07	E	AP-42 (10/96) Table 3.3-2	no	2.18E-06	1.63E-07
Total Organic Emissions					**0.0287**	**0.0022**
Total Organic HAP Emissions					**0.0283**	**0.0021**

* Emission factor in AP-42 is less than the emission rate shown (i.e., <X lb/mmBtu).

Notes:

1. Table 3.3-2 emission factors are based on uncontrolled levels of 2 diesel engines, SCC 2-02-001-02 and 2-03-001-01.

Table B-10
Deer Creek Station: Natural Gas-Fired Emergency Inlet Air Heater
Criteria Pollutant Emissions

Air Heater Properties (Note 1)

Heat Duty:	19.0	mmBtu/hr
Fluid Heated:	56% Water / 44% Ethylene Glycol	
Fluid Flow:	792,300	lb/hr
Excess Air (%):	10%	%
Moisture in Air:	0.015	lb H_2O / lb dry air
Exit Gas Temperature:	300	°F

Required Heat Input:	25.0	mmBtu/hr	gross heater release
Heating Value for Natural Gas:	1,020	Btu/scf	heating value of natural gas
Maximum Fuel Firing Rate for the Auxiliary Boiler:	24,510	scf/hr	calculated
Maximum Annual Hours of Operation:	150	hours/year	assumed

Pollutant	Emission Factor	Units	Source	Hourly Emissions (lb/hr)	Hourly Emissions (lb/mmBtu)	Annual Emissions (ton/yr)
CO (Note 2)	84	lb/mmscf	AP-42 Table 1.4-1 (7/98)	2.06	0.082	0.15
NOx (Note 3)	50	lb/mmscf	BACT	1.23	0.049	0.09
PM10 (filterable) (Note 4)	1.9	lb/mmscf	AP-42 Table 1.4-2 (7/98)	0.05	0.0020	0.00
PM10 (total) (Note 4)	7.6	lb/mmscf	AP-42 Table 1.4-2 (7/98)	0.19	0.0076	0.01
VOC (Note 4)	5.5	lb/mmscf	AP-42 Table 1.4-2 (7/98)	0.13	0.0052	0.01
SO_2 (Note 5)	0.714	lb/mmscf	calculated based on fuel sulfur content	0.02	0.0008	0.002
H_2SO_4	0.055	lb/mmscf	Calculated assuming 5% SO_2 to SO_3 conversion	0.001	4.00E-05	0.000

EXHAUST GAS PARAMETERS (perliminary)		
Gas Volume (SCFM)	4,930	SCFM
Gas Volume (ACFM)	7,605	ACFM

STACK DATA:		
Elevation	30	feet agl (approximate) Note 6
Diameter	1.55	feet (Note 6)
Exhaust Flow	7,605	acfm
Exhaust Temperature	300	°F
Exhaust Velocity	85	ft/sec (Note 6)

Notes:

1. Heater properties, exhaust gas temperature and efficiency were estimated based on specifications obtained for similar sized heaters.
2. The CO emission rates were taken from AP-42 Table 1.4-1 (Natural Gas Combustion)
3. The NOx emission rate was based on the inlet air heater BACT analysis
4. The PM and VOC emission rates were taken from AP-42 Table 1.4-2 (Natural Gas Combustion). It was assumed that PM10 = PM for natural gas combustion.
5. SO_2 emissions were based on the maximum sulfur content of the fuel, and assuming all sulfur is emitted as SO_2. For natural gas the maximum sulfur content was assumed to be 0.25 grains/100 scf.

Table B-11
Deer Creek Station: Natural Gas-Fired Emergency Inlet Air Heater
Non-Criteria Pollutant Emissions

Design Heat Input to Boiler	25.0	mmBtu/hr
Natural Gas Burned	0.025	mmscf/hr
Annual Hours of Operation	150	hours/year

Emission Factors for Natural Gas Combustion. AP-42 Section 1.4

Emission Factors for Metals from Natural Gas Combustion	Emission Factor (lb/mmscf)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Source
Arsenic	2.00E-04	5.00E-06	3.75E-07	AP-42, Table 1.4-4
Beryllium	1.20E-05	3.00E-07	2.25E-08	AP-42, Table 1.4-4
Cadmium	1.10E-03	2.75E-05	2.06E-06	AP-42, Table 1.4-4
Chromium	1.40E-03	3.50E-05	2.63E-06	AP-42, Table 1.4-4
Cobalt	8.40E-05	2.10E-06	1.58E-07	AP-42, Table 1.4-4
Manganese	3.80E-04	9.50E-06	7.13E-07	AP-42, Table 1.4-4
Mercury	2.60E-04	6.50E-06	4.88E-07	AP-42, Table 1.4-4
Nickel	2.10E-03	5.25E-05	3.94E-06	AP-42, Table 1.4-4
Selenium	2.40E-05	6.00E-07	4.50E-08	AP-42, Table 1.4-4
Lead	5.00E-04	1.25E-05	9.38E-07	AP-42 Table 1.4-2
Total Metal HAPs		**1.52E-04**	**1.14E-05**	

Speciated Organic Compounds from Natural Gas Combustion*	Emission Factor (lb/mmscf)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Source
2-Methylnaphthalene	2.40E-05	6.00E-07	4.50E-08	AP-42, Table 1.4-3
Benzene	2.10E-03	5.25E-05	3.94E-06	AP-42, Table 1.4-3
Dichlorobenzene	1.20E-03	3.00E-05	2.25E-06	AP-42, Table 1.4-3
Fluoranthene	3.00E-06	7.50E-08	5.63E-09	AP-42, Table 1.4-3
Fluorene	2.80E-06	7.00E-08	5.25E-09	AP-42, Table 1.4-3
Formaldehyde	7.50E-02	1.88E-03	1.41E-04	AP-42, Table 1.4-3
Hexane	1.80E+00	4.50E-02	3.38E-03	AP-42, Table 1.4-3
Naphthalene	6.10E-04	1.53E-05	1.14E-06	AP-42, Table 1.4-3
Phenanathrene	1.70E-05	4.25E-07	3.19E-08	AP-42, Table 1.4-3
Pyrene	5.00E-06	1.25E-07	9.38E-09	AP-42, Table 1.4-3
Toluene	3.40E-03	8.50E-05	6.38E-06	AP-42, Table 1.4-3
Total Organic HAPs		**4.71E-02**	**3.53E-03**	

Table B-12
Deer Creek Station: CT/HRSG Startup Emission Calculation
Emissions Summary

Maximum Heat Input	mmBtu/hr	1,541	maximum heat input to CT at annual average ambient conditions w/o duct firing.
Stack Diameter	ft	19	

Cold Start-up Emissions

Pollutant	Flame to FSNL	Initial Load to >50% Load	Total Emissions per Cold Start-up	Estimated Overall Cold Start-up Time	Average Emission Rate	Maximum 1-hr Average Rate During Startup	Emission Rate at Full Load (Maximum Case)
	(lbs)	(lbs)	(lbs)	(minutes)	(lb/hr)	(lb/hr)	(lb/hr)
NOx	10.0	210.5	220.5	202	65.5	78.4	29.4
CO	250.0	586.7	836.7	202	248.5	244.8	59.9
VOC	14.0	35.1	49.1	202	14.6	21.3	16.10
PM10	0.16	8.11	8.27	202	2.46	4.07	23.2
Average Flue Gas Flow (initial load to >50% load)			acfm	741,806			
Average Exhaust Velocity (initial load to >50% load)			ft/sec	43.6			

Warm Start-up Emissions

Pollutant	Flame to FSNL	Initial Load to >50% Load	Total Emissions per Warm Start-up	Estimated Overall Warm Start-up Time	Average Emission Rate	Maximum 1-hr Average Rate During Startup	Emission Rate at Full Load (Maximum Case)
	(lbs)	(lbs)	(lbs)	(minutes)	(lb/hr)	(lb/hr)	(lb/hr
NOx	10.0	77.9	87.9	98	53.8	65.3	29.4
CO	250.0	300.6	550.6	98	337.1	229.6	59.9
VOC	14.0	16.2	30.2	98	18.5	14.4	16.10
PM10	0.16	3.10	3.26	98	2.00	3.53	23.2
Average Flue Gas Flow (initial load to >50% load)			acfm	634,741			
Average Exhaust Velocity (initial load to >50% load)			ft/sec	37.3			

Hot Start-up Emissions

Pollutant	Flame to FSNL	Initial Load to >50% Load	Total Emissions per Hot Start-up	Estimated Overall Hot Start-up Time	Average Emission Rate	Maximum 1-hr Average Rate During Startup	Emission Rate at Full Load (Maximum Case)
	(lbs)	(lbs)	(lbs)	(minutes)	(lb/hr)	(lb/hr)	(lb/hr
NOx	10.0	56.2	66.2	63	63.0	NA	29.4
CO	250.0	96.6	346.6	63	330.1	NA	59.9
VOC	14.0	5.2	19.2	63	18.3	NA	16.10
PM10	0.17	1.79	1.96	63	1.87	NA	23.2
Average Flue Gas Flow (initial load to >50% load)			acfm	644,621			
Average Exhaust Velocity (initial load to >50% load)			ft/sec	37.9			

Table B-12: CT/HRSG Startup Emission Calculation – Emissions Summary continued

Maximum Heat Input	mmBtu/hr	1,541	maximum heat input to CT at annual average ambient conditions w/o duct firing.
Stack Diameter	ft	19	

Annual Emissions Associated With CT Startups

Startup Mode	Number of Startups per Year	Time Per Startup	Hours per year
	(#)	(hours)	
Cold Starts	75	3.37	252.8
Warm Starts	260	1.63	423.8
Hot Starts	30	1.05	31.5
Total Startup hours per year			708.1

NOx Emissions	Average Startup Emission Rate	Startup Hours Per Year	Annual Startup Emissions
	(lb/hr)	hr/year	tpy
Cold Starts	65.5	252.8	8.28
Warm Starts	53.8	423.8	11.40
Hot Starts	63.0	31.5	0.99
Total Startup Emissions			20.7

CO Emissions	Average Startup Emission Rate	Startup Hours Per Year	Annual Startup Emissions
	(lb/hr)	hr/year	tpy
Cold Starts	248.5	252.8	31.41
Warm Starts	337.1	423.8	71.43
Hot Starts	330.1	31.5	5.20
Total Startup Emissions			108.0

VOC Emissions	Average Startup Emission Rate	Startup Hours Per Year	Annual Startup Emissions
	(lb/hr)	hr/year	tpy
Cold Starts	14.6	252.8	1.84
Warm Starts	18.5	423.8	3.92
Hot Starts	18.3	31.5	0.29
Total Startup Emissions			6.05

Table B-13
Deer Creek Station: CT/HRSG Cold Startup NOx Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA544).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line during first 20 minutes of the cold startup.
5. Assumed 50% NOx reduction with the SCR during low-load operation.
6. For oxidation catalyst cases, assumed 50% CO reduction during low-load operation.
7. Assumed a flue gas exhast temperature of 200 °F during startup.
8. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with baseload operation.

									NOx Emissions					
	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	Uncontrolled NOx Emission Rate	% Reduction @ SCR Temp	Controlled NOx Emission Rate		Controlled NOx Emissions	Accum. NOx Emissions
	GE Graph 551HA544	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA544	Full Load annual avg. no duct firing	GE Graph 551H544	Assumed to be ~200 F	Based on 19' dia. stack	GE Graph 544HA581	Assumed	Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/hr)	%	(lb/hr)	(lb/hr)	(lb/min)	(lb)
			1,541		1,052,484		200	284		Yes				
0-27	Lightoff to FSNL	2.075%	32										10.00	10.0
28	1	24%	370	60%	631,490	930	200	37.1	100	0%	100		1.67	11.7
29	4	27%	416	60%	631,490	750	200	37.1	110	3%	107		1.78	13.5
30	7.5	30%	462	60%	631,490	805	200	37.1	135	6%	127		2.12	15.6
31	7.5	30%	462	62%	652,540	795	200	38.4	135	9%	124		2.07	17.6
32	7.5	30%	462	63%	663,065	785	200	39.0	135	11%	120		2.00	19.6
33	7.5	30%	462	65%	684,115	775	200	40.2	135	14%	117		1.95	21.6
34	7.5	30%	462	66%	694,639	765	200	40.8	135	16%	113		1.88	23.5
35	7.5	30%	462	68%	715,689	755	200	42.1	135	19%	110		1.83	25.3
36	7.5	30%	462	69%	726,214	740	200	42.7	135	21%	107		1.78	27.1
37	7.5	30%	462	70%	736,739	730	200	43.3	135	24%	103		1.72	28.8
38	7.5	30%	462	71%	747,264	720	200	43.9	135	26%	100		1.67	30.5
39	7.5	30%	462	72%	757,788	710	200	44.5	135	29%	97		1.62	32.1
40	7.5	30%	462	73%	768,313	700	200	45.2	135	31%	93		1.55	33.6
41	7.5	30%	462	73%	768,313	700	200	45.2	135	34%	90		1.50	35.1
42	7.5	30%	462	73%	768,313	700	200	45.2	135	36%	86		1.43	36.6
43	7.5	30%	462	73%	768,313	700	200	45.2	135	39%	83		1.38	38.0
44	7.5	30%	462	73%	768,313	700	200	45.2	135	41%	80		1.33	39.3
45	7.5	30%	462	73%	768,313	700	200	45.2	135	44%	76		1.27	40.6
46	7.5	30%	462	73%	768,313	700	200	45.2	135	46%	73		1.22	41.8
47	7.5	30%	462	73%	768,313	700	200	45.2	135	49%	70		1.17	42.9
48	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	44.1
49	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	45.2
50	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	46.3
51	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	47.5
52	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	48.6
53	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	49.7
54	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	50.9
55	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	52.0
56	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	53.1
57	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	54.2
58	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	55.4
59	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	56.5
60	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	57.6
61	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	58.8
62	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	59.9
63	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	61.0
64	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	62.2
65	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	63.3
66	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	64.4
67	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	65.5
68	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	66.7
69	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	67.8
70	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	68.9
71	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	70.1
72	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	71.2
73	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	72.3
74	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	73.5
75	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	74.6
76	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	75.7
77	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	76.8
78	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	78.0
79	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	79.1
80	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	80.2
81	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	81.4
82	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	82.5
83	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	83.6
84	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	84.8
85	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	85.9
86	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68		1.13	87.0
87	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	78.4	1.13	88.1
88	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	77.9	1.13	89.3
89	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	77.2	1.13	90.4
90	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	76.2	1.13	91.5
91	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	75.3	1.13	92.7
92	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	74.4	1.13	93.8
93	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	73.6	1.13	94.9
94	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	72.8	1.13	96.0
95	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	72.1	1.13	97.2
96	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	71.4	1.13	98.3
97	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	70.8	1.13	99.4
98	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	70.3	1.13	100.6
99	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	69.8	1.13	101.7
100	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	69.4	1.13	102.8
101	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	69.0	1.13	104.0
102	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	68.7	1.13	105.1
103	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	68.5	1.13	106.2
104	7.5	30%	462	73%	768,313	700	200	45.2	135	50%	68	68.3	1.13	107.4
105	7.5	32.5%	501	73%	768,313	700	200	45.2	135	50%	68	68.1	1.13	108.5
106	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	109.6
107	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	110.7
108	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	111.9
109	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	113.0
110	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	114.1
111	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	115.3
112	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	116.4
113	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	117.5
114	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	118.7
115	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	119.8
116	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	120.9
117	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	122.0
118	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	123.2
119	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	124.3
120	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	125.4
121	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	126.6
122	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	127.7
123	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	128.8
124	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	130.0
125	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	131.1
126	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	132.2
127	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	133.3
128	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	134.5
129	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	135.6
130	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	136.7
131	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	137.9
132	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	139.0
133	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	140.1
134	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	141.3
135	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	142.4
136	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	143.5
137	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	144.6
138	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	145.8
139	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	146.9
140	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	148.0

Table B-13: Cold Startup NOx Emission Details, continued

141	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	149.2
142	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	150.3
143	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	151.4
144	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	152.6
145	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	153.7
146	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	154.8
147	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	155.9
148	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	157.1
149	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	158.2
150	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	159.3
151	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	160.5
152	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	161.6
153	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	162.7
154	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	163.9
155	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	165.0
156	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	166.1
157	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	167.2
158	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	168.4
159	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	169.5
160	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	170.6
161	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	171.8
162	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	172.9
163	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	174.0
164	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	175.2
165	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	176.3
166	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	177.4
167	7.5	35%	539	73%	768,313	700	200	45.2	135	50%	68	68.0	1.13	178.5
168	7.5	35%	539	72%	757,788	719.2	200	44.5	135	50%	68	68.0	1.13	179.7
169	7.5	35%	539	71%	747,264	728.8	200	43.9	135	50%	68	68.0	1.13	180.8
170	7.5	35%	539	70%	736,739	738.5	200	43.3	135	50%	68	68.0	1.13	181.9
171	7.5	35%	539	69%	726,214	748.1	200	42.7	135	50%	68	68.0	1.13	183.1
172	7.5	35%	539	67%	705,164	757.7	200	41.5	135	50%	68	68.0	1.13	184.2
173	7.5	35%	539	66%	694,639	767.3	200	40.8	135	50%	68	68.0	1.13	185.3
174	7.5	35%	539	65%	684,115	776.9	200	40.2	135	50%	68	68.0	1.13	186.5
175	7.5	35%	539	64%	673,590	786.5	200	39.6	135	50%	68	68.0	1.13	187.6
176	7.5	35%	539	63%	663,065	796.2	200	39.0	135	50%	68	68.0	1.13	188.7
177	7.5	35%	539	62%	652,540	805.8	200	38.4	135	50%	68	68.0	1.13	189.8
178	9.1	35%	539	61%	642,015	815.4	200	37.7	146.1	51%	71	68.0	1.18	191.0
179	9.9	36%	552	61%	642,015	825.0	200	37.7	151.7	53%	72	68.1	1.20	192.2
180	10.7	36%	558	61%	642,015	834.6	200	37.7	157.2	54%	73	68.1	1.22	193.4
181	11.5	37%	565	61%	642,015	844.2	200	37.7	162.8	55%	73	68.2	1.22	194.7
182	12.3	37%	571	61%	642,015	853.8	200	37.7	168.3	56%	74	68.3	1.23	195.9
183	13.1	37%	577	61%	642,015	863.5	200	37.7	173.9	58%	74	68.4	1.23	197.1
184	13.9	38%	584	61%	642,015	873.1	200	37.7	179.4	59%	74	68.5	1.23	198.4
185	14.8	38%	590	61%	642,015	882.7	200	37.7	185.0	60%	74	68.6	1.23	199.6
186	15.6	39%	596	61%	642,015	892.3	200	37.7	190.6	61%	74	68.7	1.23	200.8
187	16.4	39%	603	61%	642,015	901.9	200	37.7	196.1	63%	74	68.8	1.23	202.0
188	17.2	40%	609	61%	642,015	911.5	200	37.7	201.7	64%	73	68.9	1.22	203.3
189	18.0	40%	615	61%	642,015	921.2	200	37.7	207.2	65%	73	69.0	1.22	204.5
190	18.8	40%	622	61%	642,015	930.8	200	37.7	212.8	66%	72	69.1	1.20	205.7
191	19.6	41%	628	61%	642,015	940.4	200	37.7	218.3	67%	71	69.1	1.18	206.9
192	20.4	41%	635	61%	642,015	950.0	200	37.7	223.9	69%	70	69.2	1.17	208.0
193	21.2	42%	641	61%	642,015	1005.6	200	37.7	229.4	70%	69	69.2	1.15	209.2
194	22.0	42%	647	61%	642,015	1033.3	200	37.7	235	71%	68	69.2	1.13	210.3
195	28.2	47%	719	61%	642,015	1061.1	200	37.7	285.0	72%	78	69.2	1.30	211.6
196	31.4	49%	754	61%	642,015	1088.9	200	37.7	310.0	74%	81	69.4	1.35	213.0
197	34.5	51%	790	61%	642,015	1116.7	200	37.7	335.0	75%	84	69.6	1.40	214.4
198	37.6	54%	826	61%	642,015	1144.4	200	37.7	360.0	76%	86	69.9	1.43	215.8
199	40.7	56%	862	61%	642,015	1172.2	200	37.7	385.0	77%	87	70.2	1.45	217.2
200	43.8	58%	897	61%	642,015	1200.0	200	37.7	410.0	79%	87	70.5	1.45	218.7
201	47.0	61%	933	65%	685,222	1153.6	200	40.3	435.0	80%	87	70.8	1.45	220.1
202	50.1	63%	969	67%	706,826	1156.7	200	41.5	120	80%	24	71.2	0.40	220.5
203	53.2	65%	1005	69%	728,430	1159.7	200	42.8	120	80%	24	70.4	0.40	220.9
204	56.3	68%	1040	71%	750,033	1162.8	200	44.1	120	80%	24	69.7	0.40	221.3
205	59.4	70%	1076	73%	771,637	1165.8	200	45.4	120	80%	24	68.9	0.40	221.7
206	62.6	72%	1112	75%	793,241	1168.9	200	46.6	120	80%	24	68.2	0.40	222.1
207	65.7	74%	1148	77%	814,844	1171.9	200	47.9	120	80%	24	67.4	0.40	222.5
208	68.8	77%	1183	79%	836,448	1175	200	49.2	120	80%	24	66.7	0.40	222.9
209	71.9	79%	1219	82%	858,051	1165.0	200	50.4	120	80%	24	65.9	0.40	223.3
210	75.0	81%	1255	84%	879,655	1160.0	200	51.7	120	80%	24	65.2	0.40	223.7
211	78.2	84%	1291	86%	901,259	1155.0	200	53.0	120	80%	24	64.5	0.40	224.1
212	81.3	86%	1326	88%	922,862	1150.0	200	54.2	120	80%	24	63.7	0.40	224.5
213	84.4	88%	1362	90%	944,466	1145.0	200	55.5	120	80%	24	63.0	0.40	224.9
214	87.5	91%	1398	92%	966,070	1140.0	200	56.8	120	80%	24	62.2	0.40	225.3
215	90.6	93%	1434	94%	987,673	1135.0	200	58.1	120	80%	24	61.5	0.40	225.7
216	93.8	95%	1469	96%	1,009,277	1130.0	200	59.3	120	80%	24	60.7	0.40	226.1
217	96.9	98%	1505	98%	1,030,880	1125.0	200	60.6	120	80%	24	60.0	0.40	226.5
218	100	100%	1541	100%	1,052,484	1120	200	61.9	120	80%	24	59.2	0.40	226.9
219	100	100%	1541	100%	1,052,484	1120	200	61.9	120	80%	24	58.5	0.40	227.3
220	100	100%	1541	100%	1,052,484	1120	200	61.9	120	80%	24	57.7	0.40	227.7

Average Flue Gas Flow (initial load to >50% load) acfm: 741,808
Average GT Heat Input (initial load to >50% load) mmBtu/hr: 624

START-UP EMISSIONS:	
Flame to Full Speed No Load (FSNL):	10.0
FSNL to >50% Load:	210.6
Total Start-up Emissions:	220.6
Average Start-up Emission Rate (lb/hr):	66.6

Table B-14
Deer Creek Station: CT/HRSG Cold Startup CO Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA544).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line during first 20 minutes
5. Assumed 50% NOx reduction with the SCR during low-load operation.
6. For oxidation catalyst cases, assumed 50% CO reduction during low-load operation.
7. Assumed a flue gas exhast temperature of 200 °F during startup.
8. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with baseload operation.

									CO Emissions					
	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	CO Emission Rate	% Reduction @ OC Temp	Controlled CO Emission Rate		Controlled CO Emissions	Accum. CO Emissions
	GE Graph 551HA544	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA544	Full Load annual avg. no duct firing	GE Graph 551H544	Assumed to be ~200 F	Based on 19' dia. stack	GE Graph 544HA561	Assumed	Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/hr)	%	(lb/hr)		(lb/min)	(lb)
			1,541		1,052,484		200	284		No				
0-27	Lightoff to FSNL	2.075%	32										250.00	250.0
28	1	24%	370	60%	631,490	930	200	37.1	180	0%	180		3.00	253.0
29	4	27%	416	60%	631,490	750	200	37.1	180	0%	180		3.00	256.0
30	7.5	30%	462	60%	631,490	805	200	37.1	180	0%	180		3.00	259.0
31	7.5	30%	462	62%	652,540	795	200	38.4	180	0%	180		3.00	262.0
32	7.5	30%	462	63%	663,065	785	200	39.0	180	0%	180		3.00	265.0
33	7.5	30%	462	65%	684,115	775	200	40.2	180	0%	180		3.00	268.0
34	7.5	30%	462	66%	694,639	765	200	40.8	180	0%	180		3.00	271.0
35	7.5	30%	462	68%	715,689	755	200	42.1	180	0%	180		3.00	274.0
36	7.5	30%	462	69%	726,214	740	200	42.7	180	0%	180		3.00	277.0
37	7.5	30%	462	70%	736,739	730	200	43.3	180	0%	180		3.00	280.0
38	7.5	30%	462	71%	747,264	720	200	43.9	180	0%	180		3.00	283.0
39	7.5	30%	462	72%	757,788	710	200	44.5	180	0%	180		3.00	286.0
40	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	289.0
41	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	292.0
42	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	295.0
43	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	298.0
44	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	301.0
45	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	304.0
46	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	307.0
47	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	310.0
48	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	313.0
49	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	316.0
50	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	319.0
51	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	322.0
52	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	325.0
53	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	328.0
54	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	331.0
55	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	334.0
56	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	337.0
57	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	340.0
58	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	343.0
59	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	346.0
60	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	349.0
61	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	352.0
62	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	355.0
63	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	358.0
64	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	361.0
65	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	364.0
66	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	367.0
67	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	370.0
68	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	373.0
69	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	376.0
70	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	379.0
71	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	382.0
72	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	385.0
73	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	388.0
74	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	391.0
75	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	394.0
76	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	397.0
77	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	400.0
78	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	403.0
79	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	406.0
80	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	409.0
81	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	412.0
82	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	415.0
83	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	418.0
84	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	421.0
85	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	424.0
86	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180		3.00	427.0
87	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	430.0
88	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	433.0
89	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	436.0
90	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	439.0
91	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	442.0
92	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	445.0
93	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	448.0
94	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	451.0
95	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	454.0
96	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	457.0
97	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	460.0
98	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	463.0
99	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	466.0
100	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	469.0
101	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	472.0
102	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	475.0
103	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	478.0
104	7.5	30%	462	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	481.0
105	7.5	32.5%	501	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	484.0
106	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	487.0
107	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	490.0
108	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	493.0
109	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	496.0
110	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	499.0
111	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	502.0
112	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	505.0
113	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	508.0
114	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	511.0
115	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	514.0
116	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	517.0
117	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	520.0
118	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	523.0
119	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	526.0
120	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	529.0
121	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	532.0
122	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	535.0
123	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	538.0
124	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	541.0
125	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	544.0
126	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	547.0
127	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	550.0
128	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	553.0
129	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	556.0
130	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	559.0
131	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	562.0
132	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	565.0
133	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	568.0
134	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	571.0
135	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	574.0
136	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	577.0
137	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	580.0
138	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	583.0
139	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	586.0
140	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	589.0

Table B-14: Cold Startup CO Emission Details, continued

141	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	592.0
142	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	595.0
143	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	598.0
144	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	601.0
145	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	604.0
146	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	607.0
147	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	610.0
148	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	613.0
149	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	616.0
150	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	619.0
151	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	622.0
152	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	625.0
153	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	628.0
154	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	631.0
155	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	634.0
156	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	637.0
157	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	640.0
158	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	643.0
159	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	646.0
160	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	649.0
161	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	652.0
162	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	655.0
163	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	658.0
164	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	661.0
165	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	664.0
166	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	667.0
167	7.5	35%	539	73%	768,313	700	200	45.2	180	0%	180	180.0	3.00	670.0
168	7.5	35%	539	72%	757,788	719.2	200	44.5	180	0%	180	180.0	3.00	673.0
169	7.5	35%	539	71%	747,264	728.8	200	43.9	180	0%	180	180.0	3.00	676.0
170	7.5	35%	539	70%	736,739	738.5	200	43.3	180	0%	180	180.0	3.00	679.0
171	7.5	35%	539	69%	726,214	748.1	200	42.7	180	0%	180	180.0	3.00	682.0
172	7.5	35%	539	67%	705,164	757.7	200	41.5	180	0%	180	180.0	3.00	685.0
173	7.5	35%	539	66%	694,639	767.3	200	40.8	180	0%	180	180.0	3.00	688.0
174	7.5	35%	539	65%	684,115	776.9	200	40.2	180	0%	180	180.0	3.00	691.0
175	7.5	35%	539	64%	673,590	786.5	200	39.6	180	0%	180	180.0	3.00	694.0
176	7.5	35%	539	63%	663,065	796.2	200	39.0	180	0%	180	180.0	3.00	697.0
177	7.5	35%	539	62%	652,540	805.8	200	38.4	180	0%	180	180.0	3.00	700.0
178	9.1	35%	539	61%	642,015	815.4	200	37.7	163.3	0%	163	180.0	2.72	702.7
179	9.9	36%	552	61%	642,015	825.0	200	37.7	155.0	0%	155	179.7	2.58	705.3
180	10.7	36%	558	61%	642,015	834.6	200	37.7	146.7	0%	147	179.3	2.45	707.8
181	11.5	37%	565	61%	642,015	844.2	200	37.7	138.3	0%	138	178.7	2.30	710.1
182	12.3	37%	571	61%	642,015	853.8	200	37.7	130.0	0%	130	178.0	2.17	712.2
183	13.1	37%	577	61%	642,015	863.5	200	37.7	121.7	0%	122	177.2	2.03	714.3
184	13.9	38%	584	61%	642,015	873.1	200	37.7	113.3	0%	113	176.2	1.88	716.1
185	14.8	38%	590	61%	642,015	882.7	200	37.7	105.0	0%	105	175.1	1.75	717.9
186	15.6	39%	596	61%	642,015	892.3	200	37.7	96.7	0%	97	173.8	1.62	719.5
187	16.4	39%	603	61%	642,015	901.9	200	37.7	88.3	0%	88	172.4	1.47	721.0
188	17.2	40%	609	61%	642,015	911.5	200	37.7	80.0	0%	80	170.8	1.33	722.3
189	18.0	40%	615	61%	642,015	921.2	200	37.7	71.7	0%	72	169.1	1.20	723.5
190	18.8	40%	622	61%	642,015	930.8	200	37.7	63.3	0%	63	167.3	1.05	724.6
191	19.6	41%	628	61%	642,015	940.4	200	37.7	55.0	0%	55	165.3	0.92	725.5
192	20.4	41%	635	61%	642,015	950.0	200	37.7	46.7	0%	47	163.2	0.78	726.3
193	21.2	42%	641	61%	642,015	1005.6	200	37.7	38.3	0%	38	160.9	0.63	726.9
194	22.0	42%	647	61%	642,015	1033.3	200	37.7	30.0	0%	30	158.5	0.50	727.4
195	28.2	47%	719	61%	642,015	1061.1	200	37.7	1025	0%	1025	156.0	17.08	744.5
196	31.4	49%	754	61%	642,015	1088.9	200	37.7	975.0	0%	975	170.3	16.25	760.7
197	34.5	51%	790	61%	642,015	1116.7	200	37.7	950.0	0%	950	183.8	15.83	776.5
198	37.6	54%	826	61%	642,015	1144.4	200	37.7	925.0	0%	925	196.8	15.42	792.0
199	40.7	56%	862	61%	642,015	1172.2	200	37.7	900.0	0%	900	209.5	15.00	807.0
200	43.8	58%	897	61%	642,015	1200.0	200	37.7	875.0	0%	875	221.7	14.58	821.5
201	47.0	61%	933	65%	685,222	1153.6	200	40.3	850	0%	850	233.4	14.17	835.7
202	50.1	63%	969	67%	706,826	1156.7	200	41.5	60	0%	60	244.8	1.00	836.7
203	53.2	65%	1005	69%	728,430	1159.7	200	42.8	60	0%	60	242.8	1.00	837.7
204	56.3	68%	1040	71%	750,033	1162.8	200	44.1	60	0%	60	240.7	1.00	838.7
205	59.4	70%	1076	73%	771,637	1165.8	200	45.4	60	0%	60	238.7	1.00	839.7
206	62.6	72%	1112	75%	793,241	1168.9	200	46.6	60	0%	60	236.7	1.00	840.7
207	65.7	74%	1148	77%	814,844	1171.9	200	47.9	60	0%	60	234.6	1.00	841.7
208	68.8	77%	1183	79%	836,448	1175	200	49.2	60	0%	60	232.6	1.00	842.7
209	71.9	79%	1219	82%	858,051	1165.0	200	50.4	60	0%	60	230.6	1.00	843.7
210	75.0	81%	1255	84%	879,655	1160.0	200	51.7	60	0%	60	228.5	1.00	844.7
211	78.2	84%	1291	86%	901,259	1155.0	200	53.0	60	0%	60	226.5	1.00	845.7
212	81.3	86%	1326	88%	922,862	1150.0	200	54.2	60	0%	60	224.5	1.00	846.7
213	84.4	88%	1362	90%	944,466	1145.0	200	55.5	60	0%	60	222.4	1.00	847.7
214	87.5	91%	1398	92%	966,070	1140.0	200	56.8	60	0%	60	220.4	1.00	848.7
215	90.6	93%	1434	94%	987,673	1135.0	200	58.1	60	0%	60	218.4	1.00	849.7
216	93.8	95%	1469	96%	1,009,277	1130.0	200	59.3	60	0%	60	216.3	1.00	850.7
217	96.9	98%	1505	98%	1,030,880	1125.0	200	60.6	60	0%	60	214.3	1.00	851.7
218	100	100%	1541	100%	1,052,484	1120	200	61.9	60	0%	60	212.3	1.00	852.7
219	100	100%	1541	100%	1,052,484	1120	200	61.9	60	0%	60	210.2	1.00	853.7
220	100	100%	1541	100%	1,052,484	1120	200	61.9	60	0%	60	208.2	1.00	854.7

Average Flue Gas Flow (initial load to >50% load) acfm: 741,806
Average GT Heat Input (initial load to >50% load) mmBtu/hr: 624

START-UP EMISSIONS:	
Flame to Full Speed No Load (FSNL):	260.0
FSNL to >50% Load:	586.7
Total Start-up Emissions:	836.7
Average Start-up Emission Rate (lb/hr):	248.6

Table B-15
Deer Creek Station: CT/HRSG Cold Startup VOC Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA544).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line during first 20 minutes
5. Assumed 50% NOx reduction with the SCR during low-load operation.
6. For oxidation catalyst cases, assumed 50% CO reduction during low-load operation.
7. Assumed a flue gas exhast temperature of 200 °F during startup.
8. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with baseload operation.

									VOC Emissions					
	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	VOC Emission Rate	% Reduction @ OC Temp	Controlled VOC Emission Rate		Controlled VOC Emissions	Accum. VOC Emissions
	GE Graph 551HA544	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA544	Full Load annual avg. no duct firing	GE Graph 551H544	Assumed to be ~200 F	Based on 18' dia. stack	GE Graph 544HA884	Assumed	Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/hr)	%	(lb/hr)		(lb/min)	(lb)
			1,541		1,052,484		200	284						
0-27	Lightoff to FSNL	2.075%	32										14.0	**14.0**
28	1	24%	370	60%	631,490	930	200	37.1	15	0%	15		0.25	14.3
29	4	27%	416	60%	631,490	750	200	37.1	10	0%	10		0.17	14.4
30	7.5	30%	462	60%	631,490	805	200	37.1	7	0%	7		0.12	14.5
31	7.5	30%	462	62%	652,540	795	200	38.4	7	0%	7		0.12	14.7
32	7.5	30%	462	63%	663,065	785	200	39.0	7	0%	7		0.12	14.8
33	7.5	30%	462	65%	684,115	775	200	40.2	7	0%	7		0.12	14.9
34	7.5	30%	462	66%	694,639	765	200	40.8	7	0%	7		0.12	15.0
35	7.5	30%	462	68%	715,689	755	200	42.1	7	0%	7		0.12	15.1
36	7.5	30%	462	69%	726,214	740	200	42.7	7	0%	7		0.12	15.3
37	7.5	30%	462	70%	736,739	730	200	43.3	7	0%	7		0.12	15.4
38	7.5	30%	462	71%	747,264	720	200	43.9	7	0%	7		0.12	15.5
39	7.5	30%	462	72%	757,788	710	200	44.5	7	0%	7		0.12	15.6
40	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	15.7
41	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	15.9
42	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	16.0
43	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	16.1
44	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	16.2
45	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	16.3
46	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	16.5
47	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	16.6
48	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	16.7
49	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	16.8
50	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	16.9
51	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	17.1
52	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	17.2
53	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	17.3
54	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	17.4
55	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	17.5
56	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	17.7
57	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	17.8
58	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	17.9
59	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	18.0
60	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	18.1
61	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	18.3
62	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	18.4
63	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	18.5
64	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	18.6
65	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	18.7
66	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	18.9
67	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	19.0
68	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	19.1
69	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	19.2
70	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	19.3
71	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	19.5
72	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	19.6
73	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	19.7
74	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	19.8
75	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	19.9
76	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	20.1
77	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	20.2
78	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	20.3
79	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	20.4
80	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	20.5
81	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	20.7
82	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	20.8
83	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	20.9
84	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	21.0
85	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	21.1
86	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7		0.12	21.3
87	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.2	0.12	21.4
88	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.1	0.12	21.5
89	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	21.6
90	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	21.7
91	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	21.9
92	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	22.0
93	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	22.1
94	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	22.2
95	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	22.3
96	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	22.5
97	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	22.6
98	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	22.7
99	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	22.8
100	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	22.9
101	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	23.1
102	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	23.2
103	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	23.3
104	7.5	30%	462	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	23.4
105	7.5	32.5%	501	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	23.5
106	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	23.7
107	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	23.8
108	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	23.9
109	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	24.0
110	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	24.1
111	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	24.3
112	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	24.4
113	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	24.5
114	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	24.6
115	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	24.7
116	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	24.9
117	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	25.0
118	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	25.1
119	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	25.2
120	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	25.3
121	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	25.5
122	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	25.6
123	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	25.7
124	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	25.8
125	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	25.9
126	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	26.1
127	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	26.2
128	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	26.3
129	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	26.4
130	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	26.5
131	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	26.7
132	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	26.8
133	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	26.9
134	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	27.0
135	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	27.1
136	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	27.3
137	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	27.4
138	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	27.5
139	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	27.6
140	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	27.7

Table B-15: Cold Startup VOC Emission Details, continued

141	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	27.9
142	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	28.0
143	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	28.1
144	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	28.2
145	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	28.3
146	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	28.5
147	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	28.6
148	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	28.7
149	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	28.8
150	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	28.9
151	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	29.1
152	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	29.2
153	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	29.3
154	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	29.4
155	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	29.5
156	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	29.7
157	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	29.8
158	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	29.9
159	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	30.0
160	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	30.1
161	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	30.3
162	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	30.4
163	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	30.5
164	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	30.6
165	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	30.7
166	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	30.9
167	7.5	35%	539	73%	768,313	700	200	45.2	7	0%	7	7.0	0.12	31.0
168	7.5	35%	539	72%	757,788	719.2	200	44.5	7	0%	7	7.0	0.12	31.1
169	7.5	35%	539	71%	747,264	728.8	200	43.9	7	0%	7	7.0	0.12	31.2
170	7.5	35%	539	70%	736,739	738.5	200	43.3	7	0%	7	7.0	0.12	31.3
171	7.5	35%	539	69%	726,214	748.1	200	42.7	7	0%	7	7.0	0.12	31.5
172	7.5	35%	539	67%	705,164	757.7	200	41.5	7	0%	7	7.0	0.12	31.6
173	7.5	35%	539	66%	694,639	767.3	200	40.8	7	0%	7	7.0	0.12	31.7
174	7.5	35%	539	65%	684,115	776.9	200	40.2	7	0%	7	7.0	0.12	31.8
175	7.5	35%	539	64%	673,590	786.5	200	39.6	7	0%	7	7.0	0.12	31.9
176	7.5	35%	539	63%	663,065	796.2	200	39.0	7	0%	7	7.0	0.12	32.1
177	7.5	35%	539	62%	652,540	805.8	200	38.4	7	0%	7	7.0	0.12	32.2
178	9.1	35%	539	61%	642,015	815.4	200	37.7	53.5	0%	54	7.0	0.90	33.1
179	9.9	36%	552	61%	642,015	825.0	200	37.7	76.8	0%	77	7.8	1.28	34.4
180	10.7	36%	558	61%	642,015	834.6	200	37.7	100	0%	100	9.0	1.67	36.0
181	11.5	37%	565	61%	642,015	844.2	200	37.7	86.9	0%	87	10.6	1.45	37.5
182	12.3	37%	571	61%	642,015	853.8	200	37.7	80.4	0%	80	11.9	1.33	38.8
183	13.1	37%	577	61%	642,015	863.5	200	37.7	73.9	0%	74	13.2	1.23	40.0
184	13.9	38%	584	61%	642,015	873.1	200	37.7	67.3	0%	67	14.3	1.12	41.2
185	14.8	38%	590	61%	642,015	882.7	200	37.7	60.8	0%	61	15.3	1.02	42.2
186	15.6	39%	596	61%	642,015	892.3	200	37.7	54.3	0%	54	16.2	0.90	43.1
187	16.4	39%	603	61%	642,015	901.9	200	37.7	47.7	0%	48	17.0	0.80	43.9
188	17.2	40%	609	61%	642,015	911.5	200	37.7	41.2	0%	41	17.7	0.68	44.6
189	18.0	40%	615	61%	642,015	921.2	200	37.7	34.7	0%	35	18.3	0.58	45.1
190	18.8	40%	622	61%	642,015	930.8	200	37.7	28.1	0%	28	18.8	0.47	45.6
191	19.6	41%	628	61%	642,015	940.4	200	37.7	21.6	0%	22	19.1	0.37	46.0
192	20.4	41%	635	61%	642,015	950.0	200	37.7	15.1	0%	15	19.4	0.25	46.2
193	21.2	42%	641	61%	642,015	1005.6	200	37.7	8.5	0%	9	19.5	0.15	46.4
194	22.0	42%	647	61%	642,015	1033.3	200	37.7	2	0%	2	19.5	0.03	46.4
195	28.2	47%	719	61%	642,015	1061.1	200	37.7	50	0%	50	19.5	0.83	47.2
196	31.4	49%	754	61%	642,015	1088.9	200	37.7	25	0%	25	20.2	0.42	47.7
197	34.5	51%	790	61%	642,015	1116.7	200	37.7	18	0%	18	20.5	0.30	48.0
198	37.6	54%	826	61%	642,015	1144.4	200	37.7	15	0%	15	20.7	0.25	48.2
199	40.7	56%	862	61%	642,015	1172.2	200	37.7	15	0%	15	20.8	0.25	48.5
200	43.8	58%	897	61%	642,015	1200.0	200	37.7	17	0%	17	20.9	0.28	48.7
201	47.0	61%	933	65%	685,222	1153.6	200	40.3	18	0%	18	21.1	0.30	49.0
202	50.1	63%	969	67%	706,826	1156.7	200	41.5	1.7	0%	2	21.3	0.03	49.1
203	53.2	65%	1005	69%	728,430	1159.7	200	42.8	1.7	0%	2	21.2	0.03	49.1
204	56.3	68%	1040	71%	750,033	1162.8	200	44.1	1.7	0%	2	21.1	0.03	49.1
205	59.4	70%	1076	73%	771,637	1165.8	200	45.4	1.7	0%	2	21.1	0.03	49.2
206	62.6	72%	1112	75%	793,241	1168.9	200	46.6	1.7	0%	2	21.0	0.03	49.2
207	65.7	74%	1148	77%	814,844	1171.9	200	47.9	1.7	0%	2	20.9	0.03	49.2
208	68.8	77%	1183	79%	836,448	1175	200	49.2	1.7	0%	2	20.8	0.03	49.3
209	71.9	79%	1219	82%	858,051	1165.0	200	50.4	1.7	0%	2	20.7	0.03	49.3
210	75.0	81%	1255	84%	879,655	1160.0	200	51.7	1.7	0%	2	20.6	0.03	49.3
211	78.2	84%	1291	86%	901,259	1155.0	200	53.0	1.7	0%	2	20.5	0.03	49.3
212	81.3	86%	1326	88%	922,862	1150.0	200	54.2	1.7	0%	2	20.5	0.03	49.4
213	84.4	88%	1362	90%	944,466	1145.0	200	55.5	1.7	0%	2	20.4	0.03	49.4
214	87.5	91%	1398	92%	966,070	1140.0	200	56.8	1.7	0%	2	20.3	0.03	49.4
215	90.6	93%	1434	94%	987,673	1135.0	200	58.1	1.7	0%	2	20.2	0.03	49.5
216	93.8	95%	1469	96%	1,009,277	1130.0	200	59.3	1.7	0%	2	20.1	0.03	49.5
217	96.9	98%	1505	98%	1,030,880	1125.0	200	60.6	1.7	0%	2	20.0	0.03	49.5
218	100	100%	1541	100%	1,052,484	1120	200	61.9	1.7	0%	2	19.9	0.03	49.6
219	100	100%	1541	100%	1,052,484	1120	200	61.9	1.7	0%	2	19.9	0.03	49.6
220	100	100%	1541	100%	1,052,484	1120	200	61.9	1.7	0%	2	19.8	0.03	49.6

Average Flue Gas Flow (initial load to >50% load) acfm: 741,806
Average GT Heat Input (initial load to >50% load) mmBtu/hr: 624

START-UP EMISSIONS:	
Flame to Full Speed No Load (FSNL):	14.0
FSNL to >50% Load:	35.1
Total Start-up Emissions:	49.1
Average Start-up Emission Rate (lb/hr):	14.6

Table B-16
Deer Creek Station: CT/HRSG Cold Startup PM Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA544).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line during first 20 minutes
5. Assumed 50% NOx reduction with the SCR during low-load operation.
6. For oxidation catalyst cases, assumed 50% CO reduction during low-load operation.
7. Assumed a flue gas exhast temperature of 200 °F during startup.
8. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with baseload operation.

	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	PM10 Emissions: PM10 Emission Rate	PM10 Emissions: PM Emission Rate		PM10 Emissions: PM Emissions	PM10 Emissions: Accum. PM10 Emissions
	GE Graph 551HA544	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA544	Full Load annual avg. no duct firing	GE Graph 551H544	Assumed to be ~200 F	Based on 18' dia. stack		Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/mmBtu)	(lb/hr)		(lb/min)	(lb)
			1,541		1,052,484		200	284					
0-27	Lightoff to FSNL	2.075%	32						0.005				0.16
28	1	24%	370	60%	631,490	930	200	37.1	0.005	1.85		0.03	0.19
29	4	27%	416	60%	631,490	750	200	37.1	0.005	2.08		0.03	0.22
30	7.5	30%	462	60%	631,490	805	200	37.1	0.005	2.31		0.04	0.26
31	7.5	30%	462	62%	652,540	795	200	38.4	0.005	2.31		0.04	0.30
32	7.5	30%	462	63%	663,065	785	200	39.0	0.005	2.31		0.04	0.34
33	7.5	30%	462	65%	684,115	775	200	40.2	0.005	2.31		0.04	0.38
34	7.5	30%	462	66%	694,639	765	200	40.8	0.005	2.31		0.04	0.42
35	7.5	30%	462	68%	715,689	755	200	42.1	0.005	2.31		0.04	0.46
36	7.5	30%	462	69%	726,214	740	200	42.7	0.005	2.31		0.04	0.50
37	7.5	30%	462	70%	736,739	730	200	43.3	0.005	2.31		0.04	0.54
38	7.5	30%	462	71%	747,264	720	200	43.9	0.005	2.31		0.04	0.58
39	7.5	30%	462	72%	757,788	710	200	44.5	0.005	2.31		0.04	0.62
40	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	0.66
41	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	0.70
42	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	0.74
43	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	0.78
44	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	0.82
45	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	0.86
46	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	0.90
47	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	0.94
48	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	0.98
49	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.02
50	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.06
51	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.10
52	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.14
53	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.18
54	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.22
55	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.26
56	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.30
57	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.34
58	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.38
59	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.42
60	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.46
61	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.50
62	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.54
63	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.58
64	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.62
65	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.66
66	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.70
67	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.74
68	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.78
69	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.82
70	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.86
71	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.90
72	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.94
73	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	1.98
74	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.02
75	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.06
76	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.10
77	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.14
78	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.18
79	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.22
80	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.26
81	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.30
82	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.34
83	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.38
84	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.42
85	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.46
86	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31		0.04	2.50
87	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.30	0.04	2.54
88	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.58
89	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.62
90	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.66
91	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.70
92	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.74
93	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.78
94	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.82
95	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.86
96	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.90
97	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.94
98	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	2.98
99	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	3.02
100	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	3.06
101	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	3.10
102	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	3.14
103	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	3.18
104	7.5	30%	462	73%	768,313	700	200	45.2	0.005	2.31	2.31	0.04	3.22
105	7.5	32.5%	501	73%	768,313	700	200	45.2	0.005	2.51	2.31	0.04	3.26
106	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.31	0.05	3.31
107	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.32	0.05	3.36
108	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.33	0.05	3.41
109	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.33	0.05	3.46
110	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.34	0.05	3.51
111	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.35	0.05	3.56
112	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.35	0.05	3.61
113	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.36	0.05	3.66
114	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.37	0.05	3.71
115	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.37	0.05	3.76
116	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.38	0.05	3.81
117	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.39	0.05	3.86
118	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.39	0.05	3.91
119	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.40	0.05	3.96
120	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.41	0.05	4.01
121	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.41	0.05	4.06
122	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.42	0.05	4.11
123	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.43	0.05	4.16
124	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.43	0.05	4.21
125	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.44	0.05	4.26
126	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.45	0.05	4.31
127	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.45	0.05	4.36
128	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.46	0.05	4.41
129	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.47	0.05	4.46
130	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.47	0.05	4.51
131	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.48	0.05	4.56
132	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.49	0.05	4.61
133	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.49	0.05	4.66
134	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.50	0.05	4.71
135	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.51	0.05	4.76
136	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.51	0.05	4.81
137	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.52	0.05	4.86
138	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.52	0.05	4.91
139	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.53	0.05	4.96
140	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.54	0.05	5.01

Table B-16: Cold Startup PM Emission Details, continued

141	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.54	0.05	5.06
142	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.55	0.05	5.11
143	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.56	0.05	5.16
144	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.56	0.05	5.21
145	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.57	0.05	5.26
146	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.58	0.05	5.31
147	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.58	0.05	5.36
148	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.59	0.05	5.41
149	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.60	0.05	5.46
150	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.60	0.05	5.51
151	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.61	0.05	5.56
152	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.62	0.05	5.61
153	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.62	0.05	5.66
154	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.63	0.05	5.71
155	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.64	0.05	5.76
156	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.64	0.05	5.81
157	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.65	0.05	5.86
158	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.66	0.05	5.91
159	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.66	0.05	5.96
160	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.67	0.05	6.01
161	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.68	0.05	6.06
162	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.68	0.05	6.11
163	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.69	0.05	6.16
164	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.70	0.05	6.21
165	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.70	0.05	6.26
166	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.70	0.05	6.31
167	7.5	35%	539	73%	768,313	700	200	45.2	0.005	2.70	2.70	0.05	6.36
168	7.5	35%	539	72%	757,788	719.2	200	44.5	0.005	2.70	2.70	0.05	6.41
169	7.5	35%	539	71%	747,264	728.8	200	43.9	0.005	2.70	2.70	0.05	6.46
170	7.5	35%	539	70%	736,739	738.5	200	43.3	0.005	2.70	2.70	0.05	6.51
171	7.5	35%	539	69%	726,214	748.1	200	42.7	0.005	2.70	2.70	0.05	6.56
172	7.5	35%	539	67%	705,164	757.7	200	41.5	0.005	2.70	2.70	0.05	6.61
173	7.5	35%	539	66%	694,639	767.3	200	40.8	0.005	2.70	2.70	0.05	6.66
174	7.5	35%	539	65%	684,115	776.9	200	40.2	0.005	2.70	2.70	0.05	6.71
175	7.5	35%	539	64%	673,590	786.5	200	39.6	0.005	2.70	2.70	0.05	6.76
176	7.5	35%	539	63%	663,065	796.2	200	39.0	0.005	2.70	2.70	0.05	6.81
177	7.5	35%	539	62%	652,540	805.8	200	38.4	0.005	2.70	2.70	0.05	6.86
178	9.1	35%	539	61%	642,015	815.4	200	37.7	0.005	2.70	2.70	0.05	6.91
179	9.9	36%	552	61%	642,015	825.0	200	37.7	0.005	2.76	2.70	0.05	6.96
180	10.7	36%	558	61%	642,015	834.6	200	37.7	0.005	2.79	2.70	0.05	7.01
181	11.5	37%	565	61%	642,015	844.2	200	37.7	0.005	2.83	2.70	0.05	7.06
182	12.3	37%	571	61%	642,015	853.8	200	37.7	0.005	2.86	2.70	0.05	7.11
183	13.1	37%	577	61%	642,015	863.5	200	37.7	0.005	2.89	2.71	0.05	7.16
184	13.9	38%	584	61%	642,015	873.1	200	37.7	0.005	2.92	2.71	0.05	7.21
185	14.8	38%	590	61%	642,015	882.7	200	37.7	0.005	2.95	2.71	0.05	7.26
186	15.6	39%	596	61%	642,015	892.3	200	37.7	0.005	2.98	2.72	0.05	7.31
187	16.4	39%	603	61%	642,015	901.9	200	37.7	0.005	3.02	2.72	0.05	7.36
188	17.2	40%	609	61%	642,015	911.5	200	37.7	0.005	3.05	2.73	0.05	7.41
189	18.0	40%	615	61%	642,015	921.2	200	37.7	0.005	3.08	2.73	0.05	7.46
190	18.8	40%	622	61%	642,015	930.8	200	37.7	0.005	3.11	2.74	0.05	7.51
191	19.6	41%	628	61%	642,015	940.4	200	37.7	0.005	3.14	2.75	0.05	7.56
192	20.4	41%	635	61%	642,015	950.0	200	37.7	0.005	3.18	2.76	0.05	7.61
193	21.2	42%	641	61%	642,015	1005.6	200	37.7	0.005	3.21	2.76	0.05	7.66
194	22.0	42%	647	61%	642,015	1033.3	200	37.7	0.005	3.24	2.77	0.05	7.71
195	28.2	47%	719	61%	642,015	1061.1	200	37.7	0.005	3.60	2.78	0.06	7.77
196	31.4	49%	754	61%	642,015	1088.9	200	37.7	0.005	3.77	2.80	0.06	7.83
197	34.5	51%	790	61%	642,015	1116.7	200	37.7	0.005	3.95	2.81	0.07	7.90
198	37.6	54%	826	61%	642,015	1144.4	200	37.7	0.005	4.13	2.84	0.07	7.97
199	40.7	56%	862	61%	642,015	1172.2	200	37.7	0.005	4.31	2.86	0.07	8.04
200	43.8	58%	897	61%	642,015	1200.0	200	37.7	0.005	4.49	2.89	0.07	8.11
201	47.0	61%	933	65%	685,222	1153.6	200	40.3	0.005	4.67	2.92	0.08	8.19
202	50.1	63%	969	67%	706,826	1156.7	200	41.5	0.005	4.85	2.95	0.08	8.27
203	53.2	65%	1005	69%	728,430	1159.7	200	42.8	0.005	5.03	2.99	0.08	8.35
204	56.3	68%	1040	71%	750,033	1162.8	200	44.1	0.005	5.20	3.03	0.09	8.44
205	59.4	70%	1076	73%	771,637	1165.8	200	45.4	0.005	5.38	3.07	0.09	8.53
206	62.6	72%	1112	75%	793,241	1168.9	200	46.6	0.005	5.56	3.12	0.09	8.62
207	65.7	74%	1148	77%	814,844	1171.9	200	47.9	0.005	5.74	3.16	0.10	8.72
208	68.8	77%	1183	79%	836,448	1175	200	49.2	0.005	5.92	3.22	0.10	8.82
209	71.9	79%	1219	82%	858,051	1165.0	200	50.4	0.005	6.10	3.27	0.10	8.92
210	75.0	81%	1255	84%	879,655	1160.0	200	51.7	0.005	6.28	3.33	0.10	9.02
211	78.2	84%	1291	86%	901,259	1155.0	200	53.0	0.005	6.46	3.39	0.11	9.13
212	81.3	86%	1326	88%	922,862	1150.0	200	54.2	0.005	6.63	3.45	0.11	9.24
213	84.4	88%	1362	90%	944,466	1145.0	200	55.5	0.005	6.81	3.52	0.11	9.35
214	87.5	91%	1398	92%	966,070	1140.0	200	56.8	0.005	6.99	3.59	0.12	9.47
215	90.6	93%	1434	94%	987,673	1135.0	200	58.1	0.005	7.17	3.66	0.12	9.59
216	93.8	95%	1469	96%	1,009,277	1130.0	200	59.3	0.005	7.35	3.74	0.12	9.71
217	96.9	98%	1505	98%	1,030,880	1125.0	200	60.6	0.005	7.53	3.82	0.13	9.84
218	100	100%	1541	100%	1,052,484	1120	200	61.9	0.005	7.71	3.90	0.13	9.97
219	100	100%	1541	100%	1,052,484	1120	200	61.9	0.005	7.71	3.98	0.13	10.10
220	100	100%	1541	100%	1,052,484	1120	200	61.9	0.005	7.71	4.07	0.13	10.23

Average Flue Gas Flow (Initial load to >50% load) acfm: 741,806
Average GT Heat Input (Initial load to >50% load) mmBtu/hr: 624

START-UP EMISSIONS:

Flame to Full Speed No Load (FSNL):	0.16
FSNL to >50% Load:	8.11
Total Start-up Emissions:	8.27
Average Start-up Emission Rate (lb/hr):	2.46

Table B-17
Deer Creek Station: CT/HRSG Warm Startup NOx Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA540).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line during first 15 minutes of the warm startup.
5. Assumed CO emissisons controlled to 180 lb/hr while holding load at 10%......
6. Assumed VOC emissions controlled to xxx while holding at ....
7. Assumed 50% NOx reduction with the SCR during low-load operation.
8. Assumed a flue gas exhast temperature of 200°F during startup.
9. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with baseload operation.

									NOx Emissions					
	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	Uncontrolled NOx Emission Rate	% Reduction @ SCR Temp	Controlled NOx Emission Rate		Controlled NOx Emissions	Accum. NOx Emissions
	GE Graph 551HA544	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA544	Full Load annual avg. no duct firing	GE Graph 551H544	Assumed to be ~200 F	Based on 19' dia. stack	GE Graph 544HA561	Assumed	Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/hr)	%	(lb/hr)	(lb/hr)	(lb/min)	(lb)
			1,541		1,052,484		200	284		Yes				
0-27	Lightoff to FSNL	2.075%	32										10.00	10.0
28	1	24%	370	30%	315,745	850	200	18.6	100	10%	90		1.50	11.5
29	4	24%	370	40%	420,994	800	200	24.7	125	15%	106		1.77	13.3
30	7.5	30%	462	50%	526,242	770	200	30.9	135	20%	108		1.80	15.1
31	10	33%	509	61%	642,015	850	200	37.7	105	25%	79		1.32	16.4
32	10	33%	509	61%	642,015	850	200	37.7	105	30%	74		1.23	17.6
33	10	33%	509	61%	642,015	850	200	37.7	105	35%	68		1.13	18.8
34	10	33%	509	61%	642,015	850	200	37.7	105	40%	63		1.05	19.8
35	10	33%	509	61%	642,015	850	200	37.7	105	45%	58		0.97	20.8
36	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	21.7
37	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	22.5
38	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	23.4
39	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	24.3
40	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	25.2
41	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	26.1
42	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	26.9
43	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	27.8
44	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	28.7
45	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	29.6
46	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	30.5
47	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	31.3
48	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	32.2
49	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	33.1
50	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	34.0
51	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	34.9
52	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	35.7
53	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	36.6
54	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	37.5
55	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	38.4
56	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	39.3
57	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	40.1
58	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	41.0
59	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	41.9
60	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	42.8
61	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	43.7
62	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	44.5
63	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	45.4
64	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	46.3
65	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	47.2
66	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	48.1
67	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	48.9
68	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	49.8
69	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	50.7
70	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	51.6
71	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	52.5
72	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	53.3
73	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	54.2
74	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	55.1
75	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	56.0
76	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	56.9
77	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	57.7
78	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	58.6
79	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	59.5
80	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	60.4
81	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	61.3
82	10	33%	509	61%	642,015	850	200	37.7	105	50%	53		0.88	62.1
83	12.2	35%	534	61%	642,015	870.0	200	37.7	127.7	50%	64		1.07	63.2
84	13.3	35%	546	61%	642,015	880.0	200	37.7	139.1	50%	70		1.17	64.4
85	14.4	36%	559	61%	642,015	890.0	200	37.7	150.5	50%	75		1.25	65.6
86	15.5	37%	572	61%	642,015	900.0	200	37.7	161.8	50%	81		1.35	67.0
87	16.5	38%	584	61%	642,015	910.0	200	37.7	173.2	50%	87	58.1	1.45	68.4
88	17.6	39%	597	61%	642,015	920.0	200	37.7	184.5	50%	92	58.0	1.53	70.0
89	18.7	40%	609	61%	642,015	930.0	200	37.7	195.9	50%	98	57.8	1.63	71.6
90	19.8	40%	622	61%	642,015	940.0	200	37.7	207.3	50%	104	57.6	1.73	73.3
91	20.9	41%	635	61%	642,015	950.0	200	37.7	218.6	50%	109	58.1	1.82	75.1
92	22	42%	647	61%	642,015	960	200	37.7	230	50%	115	58.6	1.92	77.1
93	30.7	48%	747	61%	642,015	1005.7	200	37.7	298.3	55%	134	59.4	2.23	79.3
94	35.0	52%	796	61%	642,015	1028.6	200	37.7	332.5	60%	133	60.6	2.22	81.5
95	39.3	55%	846	61%	642,015	1051.4	200	37.7	366.7	65%	128	61.9	2.13	83.6
96	43.7	58%	895	61%	642,015	1074.3	200	37.7	400.8	70%	120	63.2	2.00	85.6
97	48.0	61%	945	67%	700,654	1097.1	200	41.2	435	75%	109	64.3	1.82	87.5
98	52.3	65%	995	69%	729,973	1120	200	42.9	120	80%	24	65.3	0.40	87.9
99	56.7	68%	1044	72%	759,292	1120.0	200	44.6	120	80%	24	64.8	0.40	88.3
100	61.0	71%	1094	75%	788,611	1120.0	200	46.4	120	80%	24	64.3	0.40	88.7
101	65.3	74%	1144	78%	817,930	1120.0	200	48.1	120	80%	24	63.8	0.40	89.1
102	69.7	77%	1193	81%	847,250	1120.0	200	49.8	120	80%	24	63.3	0.40	89.5
103	74.0	81%	1243	83%	876,569	1120.0	200	51.5	120	80%	24	62.8	0.40	89.9
104	78.3	84%	1293	86%	905,888	1120.0	200	53.3	120	80%	24	62.3	0.40	90.3
105	82.7	87%	1342	89%	935,207	1120.0	200	55.0	120	80%	24	61.8	0.40	90.7
106	87.0	90%	1392	92%	964,526	1120.0	200	56.7	120	80%	24	61.3	0.40	91.1
107	91.3	94%	1442	94%	993,846	1120.0	200	58.4	120	80%	24	60.8	0.40	91.5
108	95.7	97%	1491	97%	1,023,165	1120.0	200	60.1	120	80%	24	60.4	0.40	91.9
109	100	100%	1541	100%	1,052,484	1120	200	61.9	120	80%	24	59.9	0.40	92.3
110	100	100%	1541	100%	1,052,484	1120	200	61.9	120	80%	24	59.4	0.40	92.7

Average Flue Gas Flow (initial load to >50% load) acfm:	634,741
Average GT Heat Input (initial load to >50% load) mmBtu/hr:	546

START-UP EMISSIONS:	
Flame to Full Speed No Load (FSNL):	10.0
FSNL to >50% Load:	77.9
Total Start-up Emissions:	87.9
Average Start-up Emission Rate (lb/hr):	53.8

Table B-18
Deer Creek Station: CT/HRSG Warm Startup CO Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA540).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line duri
5. Assumed CO emissisons controlled to 180 lb/hr while holding load at 10%......
6. Assumed VOC emissions controlled to xxx while holding at ....
7. Assumed 50% NOx reduction with the SCR during low-load operation.
8. Assumed a flue gas exhast temperature of 200°F during startup.
9. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with baselc

									CO Emissions					
	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	CO Emission Rate	% Reduction @ OC Temp	Controlled CO Emission Rate		Controlled CO Emissions	Accum. CO Emissions
	GE Graph 551HA544	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA544	Full Load annual avg. no duct firing	GE Graph 551H544	Assumed to be ~200 F	Based on 19' dia. stack	GE Graph 544HA561	Assumed	Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/hr)	%	(lb/hr)		(lb/min)	(lb)
			1,541		1,052,484		200	284		No				
0-27	Lightoff to FSNL	2.075%	32										250.00	250.0
28	1	24%	370	30%	315,745	850	200	18.6	180	0%	180		3.00	253.0
29	4	24%	370	40%	420,994	800	200	24.7	180	0%	180		3.00	256.0
30	7.5	30%	462	50%	526,242	770	200	30.9	1100	0%	1100		18.33	274.3
31	10	33%	509	61%	642,015	850	200	37.7	793.3	0%	793		13.22	287.6
32	10	33%	509	61%	642,015	850	200	37.7	640.0	0%	640		10.67	298.2
33	10	33%	509	61%	642,015	850	200	37.7	486.7	0%	487		8.12	306.3
34	10	33%	509	61%	642,015	850	200	37.7	333.3	0%	333		5.55	311.9
35	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	314.9
36	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	317.9
37	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	320.9
38	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	323.9
39	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	326.9
40	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	329.9
41	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	332.9
42	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	335.9
43	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	338.9
44	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	341.9
45	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	344.9
46	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	347.9
47	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	350.9
48	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	353.9
49	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	356.9
50	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	359.9
51	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	362.9
52	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	365.9
53	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	368.9
54	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	371.9
55	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	374.9
56	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	377.9
57	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	380.9
58	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	383.9
59	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	386.9
60	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	389.9
61	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	392.9
62	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	395.9
63	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	398.9
64	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	401.9
65	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	404.9
66	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	407.9
67	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	410.9
68	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	413.9
69	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	416.9
70	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	419.9
71	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	422.9
72	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	425.9
73	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	428.9
74	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	431.9
75	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	434.9
76	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	437.9
77	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	440.9
78	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	443.9
79	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	446.9
80	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	449.9
81	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	452.9
82	10	33%	509	61%	642,015	850	200	37.7	180	0%	180		3.00	455.9
83	12.2	35%	534	61%	642,015	870.0	200	37.7	152.7	0%	153		2.55	458.4
84	13.3	35%	546	61%	642,015	880.0	200	37.7	139.1	0%	139		2.32	460.8
85	14.4	36%	559	61%	642,015	890.0	200	37.7	125.5	0%	125		2.08	462.8
86	15.5	37%	572	61%	642,015	900.0	200	37.7	111.8	0%	112		1.87	464.7
87	16.5	38%	584	61%	642,015	910.0	200	37.7	98.2	0%	98	218.3	1.63	466.3
88	17.6	39%	597	61%	642,015	920.0	200	37.7	84.5	0%	85	216.9	1.42	467.8
89	18.7	40%	609	61%	642,015	930.0	200	37.7	70.9	0%	71	215.3	1.18	468.9
90	19.8	40%	622	61%	642,015	940.0	200	37.7	57.3	0%	57	197.9	0.95	469.9
91	20.9	41%	635	61%	642,015	950.0	200	37.7	43.6	0%	44	185.4	0.73	470.6
92	22	42%	647	61%	642,015	960	200	37.7	30	0%	30	175.3	0.50	471.1
93	30.7	48%	747	61%	642,015	1005.7	200	37.7	1010	0%	1010	167.6	16.83	488.0
94	35.0	52%	796	61%	642,015	1028.6	200	37.7	1000	0%	1000	179.1	16.67	504.6
95	39.3	55%	846	61%	642,015	1051.4	200	37.7	950	0%	950	192.9	15.83	520.5
96	43.7	58%	895	61%	642,015	1074.3	200	37.7	900	0%	900	206.0	15.00	535.5
97	48.0	61%	945	67%	700,654	1097.1	200	41.2	850	0%	850	218.2	14.17	549.6
98	52.3	65%	995	69%	729,973	1120	200	42.9	60	0%	60	229.6	1.00	550.6
99	56.7	68%	1044	72%	759,292	1120.0	200	44.6	60	0%	60	227.5	1.00	551.6
100	61.0	71%	1094	75%	788,611	1120.0	200	46.4	60	0%	60	225.5	1.00	552.6
101	65.3	74%	1144	78%	817,930	1120.0	200	48.1	60	0%	60	223.5	1.00	553.6
102	69.7	77%	1193	81%	847,250	1120.0	200	49.8	60	0%	60	221.4	1.00	554.6
103	74.0	81%	1243	83%	876,569	1120.0	200	51.5	60	0%	60	219.4	1.00	555.6
104	78.3	84%	1293	86%	905,888	1120.0	200	53.3	60	0%	60	217.4	1.00	556.6
105	82.7	87%	1342	89%	935,207	1120.0	200	55.0	60	0%	60	215.3	1.00	557.6
106	87.0	90%	1392	92%	964,526	1120.0	200	56.7	60	0%	60	213.3	1.00	558.6
107	91.3	94%	1442	94%	993,846	1120.0	200	58.4	60	0%	60	211.3	1.00	559.6
108	95.7	97%	1491	97%	1,023,165	1120.0	200	60.1	60	0%	60	209.2	1.00	560.6
109	100	100%	1541	100%	1,052,484	1120	200	61.9	60	0%	60	207.2	1.00	561.6
110	100	100%	1541	100%	1,052,484	1120	200	61.9	60	0%	60	205.2	1.00	562.6

Average Flue Gas Flow (initial load to >50% load) acfm: 634,741
Average GT Heat Input (initial load to >50% load) mmBtu/hr: 546

START-UP EMISSIONS:	
Flame to Full Speed No Load (FSNL):	250.0
FSNL to >50% Load:	300.6
Total Start-up Emissions:	550.6
Average Start-up Emission Rate (lb/hr):	337.1

Table B-19
Deer Creek Station: CT/HRSG Warm Startup VOC Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA540).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line duri
5. Assumed CO emissisons controlled to 180 lb/hr while holding load at 10%......
6. Assumed VOC emissions controlled to xxx while holding at ....
7. Assumed 50% NOx reduction with the SCR during low-load operation.
8. Assumed a flue gas exhast temperature of 200°F during startup.
9. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with basel

	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	VOC Emissions: VOC Emission Rate	VOC Emissions: % Reduction @ OC Temp	VOC Emissions: Controlled VOC Emission Rate		VOC Emissions: Controlled VOC Emissions	VOC Emissions: Accum. VOC Emissions
	GE Graph 551HA544	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA544	Full Load annual avg. no duct firing	GE Graph 551H544	Assumed to be ~200 F	Based on 19' dia. stack	GE Graph 544HA684	Assumed	Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/hr)	%	(lb/hr)		(lb/min)	(lb)
			1,541		1,052,484		200	284						
0-27	Lightoff to FSNL	2.075%	32										14.0	14.0
28	1	24%	370	30%	315,745	850	200	18.6	15	0%	15		0.25	14.3
29	4	24%	370	40%	420,994	800	200	24.7	10	0%	10		0.17	14.4
30	7.5	30%	462	50%	526,242	770	200	30.9	7	0%	7		0.12	14.5
31	10	33%	509	61%	642,015	850	200	37.7	100	0%	100		1.67	16.2
32	10	33%	509	61%	642,015	850	200	37.7	80	0%	80		1.33	17.5
33	10	33%	509	61%	642,015	850	200	37.7	60	0%	60		1.00	18.5
34	10	33%	509	61%	642,015	850	200	37.7	40	0%	40		0.67	19.2
35	10	33%	509	61%	642,015	850	200	37.7	30	0%	30		0.50	19.7
36	10	33%	509	61%	642,015	850	200	37.7	20	0%	20		0.33	20.0
37	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	20.2
38	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	20.4
39	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	20.6
40	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	20.7
41	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	20.9
42	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	21.1
43	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	21.2
44	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	21.4
45	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	21.6
46	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	21.7
47	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	21.9
48	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	22.1
49	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	22.3
50	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	22.4
51	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	22.6
52	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	22.8
53	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	22.9
54	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	23.1
55	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	23.3
56	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	23.4
57	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	23.6
58	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	23.8
59	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	24.0
60	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	24.1
61	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	24.3
62	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	24.5
63	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	24.6
64	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	24.8
65	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	25.0
66	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	25.1
67	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	25.3
68	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	25.5
69	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	25.7
70	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	25.8
71	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	26.0
72	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	26.2
73	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	26.3
74	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	26.5
75	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	26.7
76	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	26.8
77	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	27.0
78	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	27.2
79	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	27.4
80	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	27.5
81	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	27.7
82	10	33%	509	61%	642,015	850	200	37.7	10	0%	10		0.17	27.9
83	12.2	35%	534	61%	642,015	870.0	200	37.7	8.5	0%	9		0.15	28.0
84	13.3	35%	546	61%	642,015	880.0	200	37.7	7.8	0%	8		0.13	28.1
85	14.4	36%	559	61%	642,015	890.0	200	37.7	7.1	0%	7		0.12	28.3
86	15.5	37%	572	61%	642,015	900.0	200	37.7	6.4	0%	6		0.10	28.4
87	16.5	38%	584	61%	642,015	910.0	200	37.7	5.6	0%	6	14.4	0.10	28.5
88	17.6	39%	597	61%	642,015	920.0	200	37.7	4.9	0%	5	14.3	0.08	28.5
89	18.7	40%	609	61%	642,015	930.0	200	37.7	4.2	0%	4	14.2	0.07	28.6
90	19.8	40%	622	61%	642,015	940.0	200	37.7	3.5	0%	3	14.2	0.05	28.7
91	20.9	41%	635	61%	642,015	950.0	200	37.7	2.7	0%	3	12.5	0.05	28.7
92	22	42%	647	61%	642,015	960	200	37.7	2	0%	2	11.2	0.03	28.7
93	30.7	48%	747	61%	642,015	1005.7	200	37.7	22	0%	22	10.2	0.37	29.1
94	35.0	52%	796	61%	642,015	1028.6	200	37.7	18	0%	18	9.9	0.30	29.4
95	39.3	55%	846	61%	642,015	1051.4	200	37.7	15	0%	15	9.7	0.25	29.7
96	43.7	58%	895	61%	642,015	1074.3	200	37.7	16	0%	16	9.6	0.27	29.9
97	48.0	61%	945	67%	700,654	1097.1	200	41.2	17	0%	17	9.7	0.28	30.2
98	52.3	65%	995	69%	729,973	1120	200	42.9	1.7	0%	2	9.8	0.03	30.2
99	56.7	68%	1044	72%	759,292	1120.0	200	44.6	1.7	0%	2	9.7	0.03	30.3
100	61.0	71%	1094	75%	788,611	1120.0	200	46.4	1.7	0%	2	9.6	0.03	30.3
101	65.3	74%	1144	78%	817,930	1120.0	200	48.1	1.7	0%	2	9.4	0.03	30.3
102	69.7	77%	1193	81%	847,250	1120.0	200	49.8	1.7	0%	2	9.3	0.03	30.4
103	74.0	81%	1243	83%	876,569	1120.0	200	51.5	1.7	0%	2	9.2	0.03	30.4
104	78.3	84%	1293	86%	905,888	1120.0	200	53.3	1.7	0%	2	9.0	0.03	30.4
105	82.7	87%	1342	89%	935,207	1120.0	200	55.0	1.7	0%	2	8.9	0.03	30.5
106	87.0	90%	1392	92%	964,526	1120.0	200	56.7	1.7	0%	2	8.8	0.03	30.5
107	91.3	94%	1442	94%	993,846	1120.0	200	58.4	1.7	0%	2	8.6	0.03	30.5
108	95.7	97%	1491	97%	1,023,165	1120.0	200	60.1	1.7	0%	2	8.5	0.03	30.5
109	100	100%	1541	100%	1,052,484	1120	200	61.9	1.7	0%	2	8.4	0.03	30.6
110	100	100%	1541	100%	1,052,484	1120	200	61.9	1.7	0%	2	8.2	0.03	30.6

Average Flue Gas Flow (initial load to >50% load) acfm: 634,741
Average GT Heat Input (initial load to >50% load) mmBtu/hr: 546

START-UP EMISSIONS:	
Flame to Full Speed No Load (FSNL):	14.0
FSNL to >50% Load:	16.2
Total Start-up Emissions:	30.2
Average Start-up Emission Rate (lb/hr):	18.5

Table B-20
Deer Creek Station: CT/HRSG Warm Startup PM Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA540).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line duri
5. Assumed CO emissisons controlled to 180 lb/hr while holding load at 10%......
6. Assumed VOC emissions controlled to xxx while holding at ....
7. Assumed 50% NOx reduction with the SCR during low-load operation.
8. Assumed a flue gas exhast temperature of 200°F during startup.
9. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with basel

	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	PM10 Emissions: PM10 Emission Rate	PM10 Emissions: PM Emission Rate		PM10 Emissions: PM Emissions	PM10 Emissions: Accum. PM10 Emissions
	GE Graph 551HA544	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA544	Full Load annual avg. no duct firing	GE Graph 551H544	Assumed to be ~200 F	Based on 19' dia. stack		Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/mmBtu)	(lb/hr)		(lb/min)	(lb)
			1,541		1,052,484		200	284					
0-27	Lightoff to FSNL	2.075%	32						0.005				0.16
28	1	24%	370	30%	315,745	850	200	18.6	0.005	1.85		0.03	0.19
29	4	24%	370	40%	420,994	800	200	24.7	0.005	1.85		0.03	0.22
30	7.5	30%	462	50%	526,242	770	200	30.9	0.005	2.31		0.04	0.26
31	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.30
32	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.34
33	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.38
34	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.42
35	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.46
36	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.50
37	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.54
38	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.58
39	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.62
40	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.66
41	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.70
42	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.74
43	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.78
44	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.82
45	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.86
46	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.90
47	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.94
48	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	0.98
49	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.02
50	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.06
51	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.10
52	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.14
53	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.18
54	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.22
55	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.26
56	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.30
57	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.34
58	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.38
59	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.42
60	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.46
61	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.50
62	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.54
63	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.58
64	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.62
65	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.66
66	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.70
67	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.74
68	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.78
69	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.82
70	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.86
71	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.90
72	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.94
73	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	1.98
74	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	2.02
75	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	2.06
76	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	2.10
77	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	2.14
78	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	2.18
79	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	2.22
80	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	2.26
81	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	2.30
82	10	33%	509	61%	642,015	850	200	37.7	0.005	2.55		0.04	2.34
83	12.2	35%	534	61%	642,015	870.0	200	37.7	0.005	2.67		0.04	2.38
84	13.3	35%	546	61%	642,015	880.0	200	37.7	0.005	2.73		0.05	2.43
85	14.4	36%	559	61%	642,015	890.0	200	37.7	0.005	2.80		0.05	2.48
86	15.5	37%	572	61%	642,015	900.0	200	37.7	0.005	2.86		0.05	2.53
87	16.5	38%	584	61%	642,015	910.0	200	37.7	0.005	2.92	2.54	0.05	2.58
88	17.6	39%	597	61%	642,015	920.0	200	37.7	0.005	2.99	2.55	0.05	2.63
89	18.7	40%	609	61%	642,015	930.0	200	37.7	0.005	3.05	2.57	0.05	2.68
90	19.8	40%	622	61%	642,015	940.0	200	37.7	0.005	3.11	2.59	0.05	2.73
91	20.9	41%	635	61%	642,015	950.0	200	37.7	0.005	3.18	2.60	0.05	2.78
92	22	42%	647	61%	642,015	960	200	37.7	0.005	3.24	2.61	0.05	2.83
93	30.7	48%	747	61%	642,015	1005.7	200	37.7	0.005	3.74	2.62	0.06	2.89
94	35.0	52%	796	61%	642,015	1028.6	200	37.7	0.005	3.98	2.64	0.07	2.96
95	39.3	55%	846	61%	642,015	1051.4	200	37.7	0.005	4.23	2.66	0.07	3.03
96	43.7	58%	895	61%	642,015	1074.3	200	37.7	0.005	4.48	2.69	0.07	3.10
97	48.0	61%	945	67%	700,654	1097.1	200	41.2	0.005	4.73	2.72	0.08	3.18
98	52.3	65%	995	69%	729,973	1120	200	42.9	0.005	4.98	2.76	0.08	3.26
99	56.7	68%	1044	72%	759,292	1120.0	200	44.6	0.005	5.22	2.80	0.09	3.35
100	61.0	71%	1094	75%	788,611	1120.0	200	46.4	0.005	5.47	2.85	0.09	3.44
101	65.3	74%	1144	78%	817,930	1120.0	200	48.1	0.005	5.72	2.90	0.10	3.54
102	69.7	77%	1193	81%	847,250	1120.0	200	49.8	0.005	5.97	2.95	0.10	3.64
103	74.0	81%	1243	83%	876,569	1120.0	200	51.5	0.005	6.22	3.01	0.10	3.74
104	78.3	84%	1293	86%	905,888	1120.0	200	53.3	0.005	6.47	3.07	0.11	3.85
105	82.7	87%	1342	89%	935,207	1120.0	200	55.0	0.005	6.71	3.14	0.11	3.96
106	87.0	90%	1392	92%	964,526	1120.0	200	56.7	0.005	6.96	3.21	0.12	4.08
107	91.3	94%	1442	94%	993,846	1120.0	200	58.4	0.005	7.21	3.28	0.12	4.20
108	95.7	97%	1491	97%	1,023,165	1120.0	200	60.1	0.005	7.46	3.36	0.12	4.32
109	100	100%	1541	100%	1,052,484	1120	200	61.9	0.005	7.71	3.44	0.13	4.45
110	100	100%	1541	100%	1,052,484	1120	200	61.9	0.005	7.71	3.53	0.13	4.58

Average Flue Gas Flow (initial load to >50% load) acfm:	634,741
Average GT Heat Input (initial load to >50% load) mmBtu/hr:	546

START-UP EMISSIONS:	
Flame to Full Speed No Load (FSNL):	0.2
FSNL to >50% Load:	3.10
Total Start-up Emissions:	3.26
Average Start-up Emission Rate (lb/hr):	2.00

Table B-21
Deer Creek Station: CT/HRSG Hot Startup NOx and CO Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA533).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560, prorated for shorter lightoff to initial load time.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line during first 10 minutes of the warm startup.
5. Assumed CO emissions controlled to 180 lb/hr while holding load at 10%.....
6. Assumed VOC emissions controlled to xxx while holding at .....
7. Assumed 50% NOx reduction with the SCR during low-load operation.
8. Assumed a flue gas exhaust temperature of 200F during startup.
9. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with baseload operation.

	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	NOx Emissions: Uncontrolled NOx Emission Rate	NOx Emissions: % Reduction @ SCR Temp	NOx Emissions: Controlled NOx Emission Rate		NOx Emissions: Controlled NOx Emissions	NOx Emissions: Accum. NOx Emissions	CO Emissions: CO Emission Rate	CO Emissions: % Reduction @ OC Temp	CO Emissions: Controlled CO Emission Rate		CO Emissions: Controlled CO Emissions	CO Emissions: Accum. CO Emissions
	GE Graph 551HA536	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA536	Full Load annual avg. no duct firing	GE Graph 551H536	Assumed to be ~200 F	Based on 19' dia. stack	GE Graph 544HA561	Assumed	Instantaneous	Rolling 1-hour Average			GE Graph 544HA561	Assumed	Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/hr)	%	(lb/hr)	(lb/hr)	(lb/min)	(lb)	(lb/hr)	%	(lb/hr)		(lb/min)	(lb)
			1,541		1,052,464		200	204		Yes						No				
0-28	Lightoff to FSNL	2.15%	33										10.00	10.0					250.00	250.0
29	1	25%	385	61%	842,015	750	200	37.7	100	10%	90		1.50	11.5	180	0%	180		3.00	253.0
30	7.5	30%	462	61%	842,015	815	200	37.7	135	20%	108		1.80	13.3	180	0%	180		3.00	256.0
31	15.75	35%	539	61%	842,015	890	200	37.7	135	30%	95		1.58	14.9	1000	0%	1000		16.67	272.7
32	23	40%	616	61%	842,015	950	200	37.7	200	40%	120		2.00	16.9	90	0%	90		1.50	274.2
33	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	18.6	90	0%	90		1.50	275.7
34	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	20.2	90	0%	90		1.50	277.2
35	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	21.9	90	0%	90		1.50	278.7
36	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	23.6	90	0%	90		1.50	280.2
37	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	25.3	90	0%	90		1.50	281.7
38	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	26.9	90	0%	90		1.50	283.2
39	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	28.6	90	0%	90		1.50	284.7
40	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	30.2	90	0%	90		1.50	286.2
41	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	31.9	90	0%	90		1.50	287.7
42	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	33.6	90	0%	90		1.50	289.2
43	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	35.3	90	0%	90		1.50	290.7
44	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	36.9	90	0%	90		1.50	292.2
45	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	38.6	90	0%	90		1.50	293.7
46	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	40.3	90	0%	90		1.50	295.2
47	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	41.9	90	0%	90		1.50	296.7
48	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	43.6	90	0%	90		1.50	298.2
49	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	45.3	90	0%	90		1.50	299.7
50	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	46.9	90	0%	90		1.50	301.2
51	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	48.6	90	0%	90		1.50	302.7
52	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	50.3	90	0%	90		1.50	304.2
53	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	52.0	90	0%	90		1.50	305.7
54	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	53.6	90	0%	90		1.50	307.2
55	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	55.3	90	0%	90		1.50	308.7
56	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	57.0	90	0%	90		1.50	310.2
57	23	40%	616	61%	842,015	950	200	37.7	200	50%	100		1.67	58.6	90	0%	90		1.50	311.7
58	23	40%	616	61%	842,015	950	200	37.7	200	55%	90		1.50	60.1	90	0%	90		1.50	313.2
59	23	40%	616	61%	842,015	950	200	37.7	200	60%	80		1.33	61.5	90	0%	90		1.50	314.7
60	23	40%	616	61%	842,015	975	200	37.7	175	65%	61		1.02	62.5	30	0%	30		0.50	315.2
61	37.0	51%	785	61%	842,015	1090	200	37.7	310	70%	93		1.55	64.0	975	0%	975		16.25	331.4
62	44.0	56%	869	61%	842,015	1200	200	37.7	410	75%	103		1.72	65.8	850	0%	850		14.17	345.6
63	51.0	62%	953	70%	733,231	1190	200	43.1	120	80%	24		0.40	66.2	60	0%	60		1.00	346.6
64	58.0	67%	1037	74%	778,838	1180	200	45.8	120	80%	24		0.40	66.6	60	0%	60		1.00	347.6
65	65.0	73%	1121	78%	824,446	1170	200	48.5	120	80%	24		0.40	67.0	60	0%	60		1.00	348.6
66	72.0	78%	1206	83%	870,053	1160	200	51.1	120	80%	24		0.40	67.4	60	0%	60		1.00	349.6
67	79.0	84%	1289	87%	915,661	1150	200	53.8	120	80%	24		0.40	67.8	60	0%	60		1.00	350.6
68	86.0	89%	1373	91%	961,269	1140	200	56.5	120	80%	24		0.40	68.2	60	0%	60		1.00	351.6
69	93.0	95%	1457	96%	1,006,876	1130	200	59.2	120	80%	24		0.40	68.6	60	0%	60		1.00	352.6
70	100	100%	1541	100%	1,052,464	1120	200	61.9	120	80%	24		0.40	69.0	60	0%	60		1.00	353.6
71	100		0	100%	1,052,464	1120	200	61.9	120	80%	24		0.40	69.4	60	0%	60		1.00	354.6
72	100		0	100%	1,052,464	1120	200	61.9	120	80%	24		0.40	69.8	60	0%	60		1.00	355.6

Average Flue Gas Flow (initial load to >50% load) acfm: 844,821
Average GT Heat Input (initial load to >50% load) mmBtu/hr: 624

NOx START-UP EMISSIONS:	
Flame to Full Speed No Load (FSNL):	10.0
FSNL to >50% Load:	56.2
Total Start-up Emissions:	66.2
Average Start-up Emission Rate (lb/hr):	63.0

CO START-UP EMISSIONS:	
Flame to Full Speed No Load (FSNL):	250.0
FSNL to >50% Load:	96.6
Total Start-up Emissions:	346.6
Average Start-up Emission Rate (lb/hr):	330.1

Table B-22
Deer Creek Station: CT/HRSG Hot Startup VOC and PM Emission Details

Notes:

1. Time from lightoff to initial load for cold startup is approximately 28 minutes (GE Graph 551HA533).
2. NOx and CO emissions from lightoff to FSNL taken from GE Graph 544HA560, prorated for shorter lightoff to initial load time.
3. VOC emissions from lightoff to FSNL were based on the CO emission rate and a CO:VOC ratio of 25:1.4.
4. Assumed that the SCR and SCR catalyst is heated during lightoff to FSNL and that the SCR is brought on-line during first 10 minutes of t
5. Assumed CO emissions controlled to 100 lb/hr while holding load at 10%.....
6. Assumed VOC emissions controlled to xxx while holding at ....
7. Assumed 50% NOx reduction with the SCR during low-load operation.
8. Assumed a flue gas exhaust temperature of 200°F during startup.
9. Startup ends when the GT load exceeds 50% and all emissions are controlled to a level commensurate with baseload operation.

									VOC Emissions						PM10 Emissions				
	Combustion Turbine Load	GT Heat Consumption		GT Exhaust		GT Exhaust Temperature	Exhaust Gas Temperature	Stack Gas Velocity	VOC Emission Rate	% Reduction @ OC Temp	Controlled VOC Emission Rate		Controlled VOC Emissions	Accum. VOC Emissions	PM10 Emission Rate	PM Emission Rate		PM Emissions	Accum. PM10 Emissions
	GE Graph 551HA536	GE Graph 551HA542	GT Heat Consumption	GE Graph 551HA536	Full Load annual avg. no duct firing	GE Graph 551H536	Assumed to be ~200 F	Based on 19' dia. stack	GE Graph 544HA534	Assumed	Instantaneous	Rolling 1-hour Average				Instantaneous	Rolling 1-hour Average		
Minutes	%	% of full	mmBtu/hr	% of Full	acfm	deg. F	deg. F	ft/sec	(lb/hr)	%	(lb/hr)		(lb/min)	(lb)	(lb/mmBtu)	(lb/hr)		(lb/min)	(lb)
			1,541		1,052,484		200	284											
0-28	Lightoff to FSNL	2.15%	33										14.0	14.0	0.005				0.17
29	1	25%	385	61%	842,015	750	200	37.7	15	0%	15		0.25	14.3	0.005	1.93		0.03	0.20
30	7.5	30%	462	61%	842,015	815	200	37.7	7	0%	7		0.12	14.4	0.005	2.31		0.04	0.24
31	13.75	35%	539	61%	842,015	880	200	37.7	60	0%	60		1.00	15.4	0.005	2.70		0.05	0.29
32	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	15.5	0.005	3.08		0.05	0.34
33	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	15.5	0.005	3.08		0.05	0.39
34	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	15.6	0.005	3.08		0.05	0.44
35	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	15.7	0.005	3.08		0.05	0.49
36	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	15.8	0.005	3.08		0.05	0.54
37	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	15.9	0.005	3.08		0.05	0.59
38	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	15.9	0.005	3.08		0.05	0.64
39	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.0	0.005	3.08		0.05	0.69
40	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.1	0.005	3.08		0.05	0.74
41	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.2	0.005	3.08		0.05	0.79
42	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.3	0.005	3.08		0.05	0.84
43	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.3	0.005	3.08		0.05	0.89
44	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.4	0.005	3.08		0.05	0.94
45	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.5	0.005	3.08		0.05	0.99
46	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.6	0.005	3.08		0.05	1.04
47	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.7	0.005	3.08		0.05	1.09
48	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.7	0.005	3.08		0.05	1.14
49	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.8	0.005	3.08		0.05	1.19
50	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	16.9	0.005	3.08		0.05	1.24
51	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	17.0	0.005	3.08		0.05	1.29
52	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	17.1	0.005	3.08		0.05	1.34
53	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	17.1	0.005	3.08		0.05	1.39
54	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	17.2	0.005	3.08		0.05	1.44
55	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	17.3	0.005	3.08		0.05	1.49
56	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	17.4	0.005	3.08		0.05	1.54
57	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	17.5	0.005	3.08		0.05	1.59
58	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	17.5	0.005	3.08		0.05	1.64
59	20	40%	616	61%	842,015	950	200	37.7	5	0%	5		0.08	17.6	0.005	3.08		0.05	1.69
60	23	40%	616	61%	842,015	975	200	37.7	60	0%	60		1.00	18.6	0.005	3.08		0.05	1.74
61	37.0	51%	785	61%	842,015	1090	200	37.7	17	0%	17		0.28	18.9	0.005	3.93		0.07	1.81
62	44.0	56%	869	61%	842,015	1200	200	37.7	15	0%	15		0.25	19.1	0.005	4.35		0.07	1.88
63	51.0	62%	953	70%	733,251	1190	200	43.1	1.7	0%	2		0.03	19.2	0.005	4.77		0.08	1.96
64	58.0	67%	1037	74%	778,838	1180	200	45.8	1.7	0%	2		0.03	19.2	0.005	5.19		0.09	2.05
65	65.0	73%	1121	78%	824,446	1170	200	48.5	1.7	0%	2		0.03	19.2	0.005	5.61		0.09	2.14
66	72.0	78%	1205	83%	870,053	1160	200	51.1	1.7	0%	2		0.03	19.3	0.005	6.03		0.10	2.24
67	79.0	84%	1289	87%	915,661	1150	200	53.8	1.7	0%	2		0.03	19.3	0.005	6.45		0.11	2.35
68	86.0	89%	1373	91%	961,269	1140	200	56.5	1.7	0%	2		0.03	19.3	0.005	6.87		0.11	2.46
69	93.0	95%	1457	96%	1,006,876	1130	200	59.2	1.7	0%	2		0.03	19.4	0.005	7.29		0.12	2.58
70	100	100%	1541	100%	1,052,484	1120	200	61.9	1.7	0%	2		0.03	19.4	0.005	7.71		0.13	2.71
71	100		0	100%	1,052,484	1120	200	61.9	1.7	0%	2		0.03	19.4	0.005	0.00		0.00	2.71
72	100		0	100%	1,052,484	1120	200	61.9	1.7	0%	2		0.03	19.4	0.005	0.00		0.00	2.71

Average Flue Gas Flow (initial load to >50% load) acfm: 844,821
Average GT Heat Input (initial load to >50% load) mmBtu/hr: 624

START-UP EMISSIONS (VOC):	
Flame to Full Speed No Load (FSNL):	14.0
FSNL to >50% Load:	5.2
Total Start-up Emissions:	19.2
Average Start-up Emission Rate (lb/hr):	16.3

START-UP EMISSIONS (PM10):	
Flame to Full Speed No Load (FSNL):	0.17
FSNL to >50% Load:	1.79
Total Start-up Emissions:	1.96
Average Start-up Emission Rate (lb/hr):	1.67

Basin Electric Power Cooperative

Deer Creek Station
PSD Air Quality Construction Permit Application

Appendix C
Best Available Control Technology Analysis

Prepared by:

Sargent & Lundy, LLC
Chicago, Illinois

May 29, 2009

Table of Contents

1.0 Project Description

2.0 Best Available Control Technology (BACT)

2.1 Definition of BACT
2.2 The "Top-Down" BACT Analysis
2.3 PSD Applicability

3.0 BACT Analysis for Combustion Turbine NOx Control
3.1 Step 1: Identify Potentially Feasible NOx Control Options
3.2 Step 2: Technical Feasibility of Potential NOx Control Options
3.2.1 Combustion Controls
3.2.1.1 Water/Steam Injection
3.2.1.2 Dry Low-NOx Combustion
3.2.2 Post-Combustion NOx Controls
3.2.2.1 Selective Catalytic Reduction
3.2.2.2 SCR with Ammonia Oxidation Catalyst (Zero-Slip™)
3.2.2.3 Oxidation Catalyst with Potassium Carbonate Absorption (EMx™ formerly SCONOx™)
3.2.2.4 Urea Injection Systems (Selective Non-Catalytic Reduction and NOxOut™)
3.2.2.5 Ammonia Injection Systems (Thermal DeNOx™)
3.2.2.6 Catalytic Combustion (Xonon™)
3.3 Step 3: Rank the Technically Feasible NOx Control Options by Effectiveness
3.4 Step 4: Evaluate the Technically Feasible NOx Control Options
3.4.1 NOx Control Technologies - Economic Impact Evaluation
3.4.2 NOx Control Technologies – Environmental Impact Evaluation
3.4.2 NOx Control Technologies – Energy Impact Evaluation
3.5 Step 5: Select BACT for NOx Control

4.0 BACT Analysis for Combustion Turbine CO Control
4.1 Step 1: Identify Potentially Feasible CO Control Options
4.2 Step 2: Technical Feasibility of Potential CO Control Options
4.2.1 Combustion Controls
4.2.2 Post-Combustion CO Controls
4.2.2.1 Oxidation Catalyst
3.2.2.2 Oxidation Catalyst with Potassium Carbonate Absorption (EMx™ formerly SCONOx™)
3.2.2.3 Catalytic Combustion (Xonon™)
4.3 Step 3: Rank the Technically Feasible CO Control Options by Effectiveness
4.4 Step 4: Evaluate the Technically Feasible CO Control Options
4.4.1 CO Control Technologies - Economic Impact Evaluation
4.4.2 CO Control Technologies – Environmental Impact Evaluation

Table of Contents

4.4.2 CO Control Technologies – Energy Impact Evaluation
4.5 Step 5: Select BACT for CO Control

5.0 BACT Analysis for Combustion Turbine PM Control
5.1 Step 1: Identify Potentially Feasible PM Control Options
5.2 Step 2: Technical Feasibility of Potential PM Control Options
5.3 Step 3: Rank the Technically Feasible PM Control Options by Effectiveness
5.4 Step 4: Evaluate the Technically Feasible PM Control Options
5.4.1 PM Control Technologies - Economic Impact Evaluation
5.4.2 PM Control Technologies – Environmental Impact Evaluation
5.5 Step 5: Select BACT for PM Control

6.0 BACT Analysis for the Emergency Generator, Fire Water Pump, and Emergency Inlet Air Heater
6.1 Emergency Generator and Fire Water Pump BACT Analysis
6.1.1 Diesel Engine – Baseline Emission Rates
6.1.2 Diesel Engine – Potentially Feasible Emission Control Technologies
6.1.2.1 Combustion Controls
6.1.2.2 Post-Combustion Control Technologies
6.1.2.2.1 NOx Absorption Systems
6.1.2.2.2 Catalytic Reduction Systems
6.1.2.2.3 Particulate Control Systems
6.1.3 Diesel Engine – Controlled Emission Rates
6.1.4 Post-Combustion Emission Control Cost Effectiveness Evaluation
6.1.5 Proposed Emergency Generator and Fire Water Pump BACT
6.2 Emergency Inlet Air Heater BACT Analysis
6.2.1 Emergency Inlet Air Heater – Potential Emissions
6.2.2 Emergency Inlet Air Heater – Potentially Feasible Emission Control Technologies
6.2.3 Emergency Inlet Air Heater – Controlled Emission Rates
6.2.4 Proposed Emergency Inlet Air Heater BACT

7.0 Deer Creek Station – BACT Summary

Attachment A – RBLC Tables
Attachment B – CT/HRSG CO Control Cost Estimates

Best Available Control Technology

1.0 PROJECT DESCRIPTION

Basin Electric Power Cooperative (BEPC) proposes to construct a new natural gas-fired combined cycle (NGCC) electric generating facility. The new facility, to be know as the Deer Creek Station, will be located in Brookings County, South Dakota, approximately fifteen miles northeast of the town of Brookings and six miles southeast of White, South Dakota. The location of the proposed Deer Creek Station is shown in Figure 1-1.

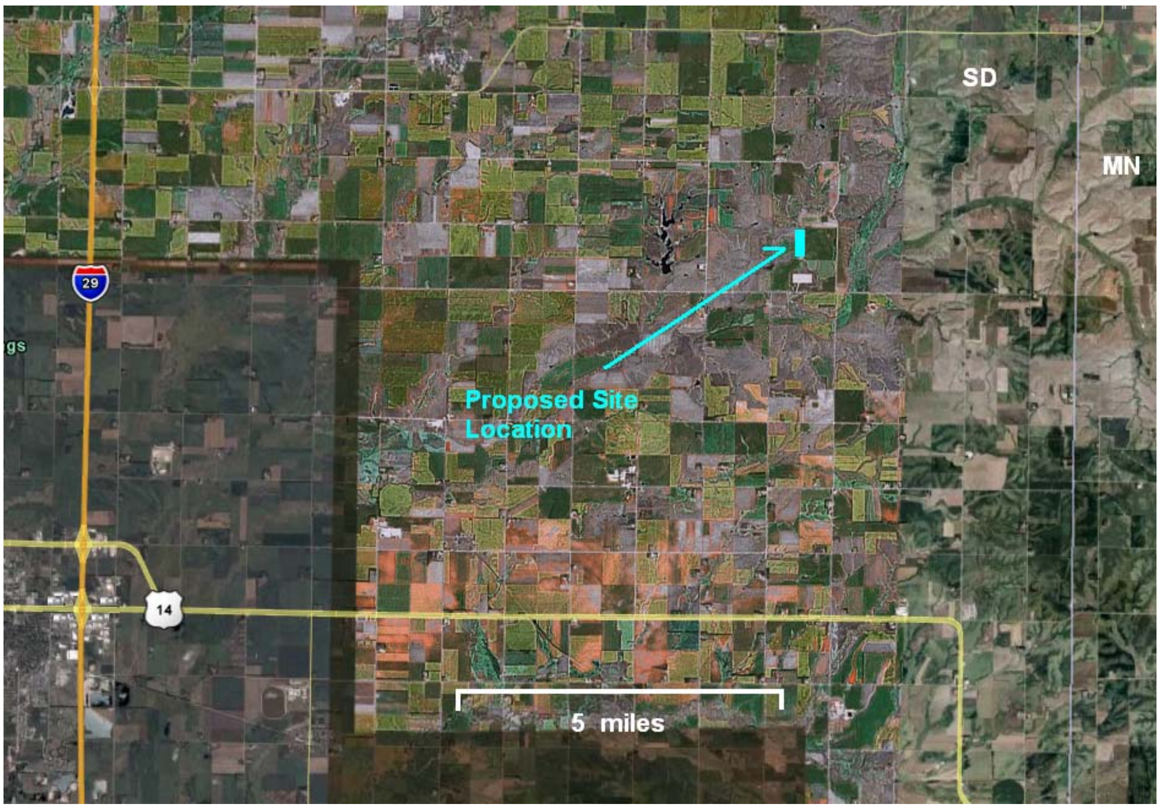
Upon completion the Deer Creek Station will include:

- one F-class combustion turbine generator (CTG);
- one natural circulation, duct fired, heat recovery steam generator (HRSG);
- one reheat condensing steam turbine generator (STG);
- one diesel-fired emergency generator;
- one diesel-fired fire water pump;
- one natural gas-fired emergency inlet air heater; and
- one air cooled condenser (ACC).

The proposed electric generating facility has the potential to emit regulated pollutants in amounts above the significance levels defined in 40 CFR 52.21(b)(23). Therefore, BEPC is applying to the South Dakota Department of Environmental and Natural Resources (DENR) for a New Source Review (NSR) Prevention of Significant Deterioration (PSD) Air Quality Construction Permit. New emission sources subject to PSD review are required to control emissions of regulated NSR pollutants using the Best Available Control Technology (BACT). BACT is determined on a case-by-case basis, based on a detailed analysis of the emission control technologies available to reduce emissions from the proposed facility. This BACT Analysis has been prepared to support BEPC's PSD air construction permit application for the Deer Creek Station.

The proposed NGCC facility is being designed to provide approximately 250 MW-gross output at full load at annual average ambient conditions without supplemental duct firing, and approximately 310 MW-gross output at full load with auxiliary duct firing in the HRSG. Design output of the unit will vary depending on ambient conditions and supplemental duct firing in the HRSG. NGCC operating parameters used to form the basis of this BACT Analysis are summarized in Table 1-1.

Figure 1-1
Location of the Proposed Deer Creek Station



Best Available Control Technology

Table 1-1
Deer Creek Station Design Parameters

Plant Performance		**Ambient Conditions**			
		Winter Extreme Conditions	**Average Annual Conditions**	**Average Annual Conditions**	**Summer Ambient Conditions**
Ambient Temperature	^{o}F	-41	43	43	94
Duct Firing	Yes/No	No	No	Yes	Yes
Combustion Turbine Load	%	base load	base load	base load	base load
Heat Input to Combustion Turbine	mmBtu/hr (LHV)	1,713	1,541	1,541	1,434
Combustion Turbine Output	kW (gross)	184,557	166,178	166,178	150,600
Duct Firing Heat Input	mmBtu/hr (LHV)	0.0	0.0	511	610
Steam Turbine Output	kW (gross)	85,326	83,505	142,723	152,860
Gross Plant Output	kW (gross)	269,883	249,683	308,901	303,460
Auxiliary Power Requirements	kW	5,390	6,507	8,528	10,884
Net Plant Output	kW (net)	264,493	243,176	300,373	292,576
Net Plant Heat Rate	Btu/kWh (LHV)	6,477	6,337	6,832	6,988

Best Available Control Technology

2.0 BEST AVAILABLE CONTROL TECHNOLOGY

2.1 Definition of BACT

The requirement to conduct a BACT analysis is set forth in section 165(a)(4) of the Clean Air Act, and has been codified into federal regulations at 40 CFR 52.21(j). BACT is defined in 40 CFR 52.21(b)(12)[1] as:

> an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant….

The primary guidance utilized in preparation of this BACT Analysis is U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990 ("NSR Manual"). The NSR Manual describes a "top-down" approach to the determination of BACT controls for new emission sources.

2.2 The "Top-Down" BACT Analysis

In general, a top-down BACT Analysis involves the following steps for each pollutant:

1. Identify all potential control technologies;
2. Eliminate technically infeasible control options;
3. Rank the remaining control technologies by control effectiveness;
4. Evaluate the control technologies, starting with the most effective for:
   - economic impacts,
   - energy impacts, and
   - environmental impacts;
5. Select BACT

A more detailed description of each step in the BACT Analysis is provided below.

Step 1 - Identify All Control Options

[1] The definition of BACT in 40 CFR 52.21(b)(12) has been incorporated by reference into the South Dakota Air Regulations at 74:36:09:02.

Best Available Control Technology

The first step in the BACT Analysis is to identify, for the emission unit in question, all available control options. Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. An evaluation of alternative source designs is generally outside the scope of BACT.

In an effort to identify all potentially applicable emission control technologies, BEPC's engineering consultant, Sargent & Lundy LLC (S&L) searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) Database;
- New & Emerging Environmental Technologies (NEET) Database;
- EPA's New Source Review (NSR) and Clean Air Technology Center (CATC) websites;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and BACT determinations for similar sources;
- Recently submitted Federal and State NSR permit applications submitted for coal-fired PC electrical generating projects; and
- Technical journals, reports, newsletters and air pollution control seminars.

Step 2 - Eliminate Technically Infeasible Control Options

The second step in the BACT Analysis is to review the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. A demonstration of technical unfeasibility must be based on physical, chemical, and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility. Options that are technically infeasible for the intended application are eliminated from further review.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All technically feasible options are ranked in order of over all control effectiveness. Control effectiveness is generally expressed as the rate that a pollutant is emitted after the control system. The most effective control option is the system that achieves the lowest emissions level.

Best Available Control Technology

Step 4 - Evaluate Most Effective Controls

After identifying the technically feasible control options, each option, beginning with the most effective, is evaluated for economic, energy, and environmental impacts. Both beneficial and adverse impacts should be assessed and, where possible, quantified. In the event that the most effective control alternative is shown to be inappropriate due to energy, environmental, or economic impacts, the basis for this finding is documented and the next most stringent alternative evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts.

Economic Analysis

If required, the economic analysis performed as part of the BACT determination examines the cost-effectiveness of each control technology, on a dollar per ton of pollutant removed basis. Annual emissions using a particular control device are subtracted from base case emissions to calculate tons of pollutant controlled per year. The base case generally represents uncontrolled emissions or the inherent emission rate from the proposed source. Annual costs are calculated by adding annual operation and maintenance costs to the annualized capital cost of an option. Cost effectiveness ($/ton) of an option is simply the annual cost ($/yr) divided by the annual pollution controlled (ton/yr).

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control may also be calculated to evaluate the cost effectiveness of the more stringent control.

Energy Impact Analysis

The energy requirements of a control technology should be examined to determine whether the use of that technology results in any significant or unusual energy penalties or benefits. Two forms of energy impacts associated with a control option can normally be quantified. First, increases in energy consumption resulting from increased heat rate may be shown as total Btu's or fuel consumed per year, or as Btu's per ton of pollutant controlled. Second, the installation of a particular control option may reduce the output and/or reliability of equipment. This reduction would result in loss of revenue from power sales and/or increased fuel consumption due to use of less efficient electrical and steam generation methods.

Best Available Control Technology

Environmental Impact Analysis

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal. The environmental impact analysis should be made on a consideration of site-specific circumstances.

Step 5 - Select BACT

The determination of BACT for each pollutant and emissions unit is based on a review of the three impact categories and the technical factors that affect feasibility of the control alternatives under consideration.

2.3 PSD Applicability

The PSD permitting regulations (Chapter 74:36:09 of the South Dakota air pollution control regulations) apply to the construction of a new major source of emissions located in an attainment or unclassified area. The proposed Deer Creek Station will be located in Brookings County. Brookings County has been designated as an attainment area (or unclassifiable) for all national ambient air quality standards. Based on potential-to-emit emission calculations, the proposed facility meets the definition of a new major source of emissions.[2]

Once a source is considered major, all regulated air pollutants emitted in significant emission rates (as defined in 40 CFR 52.21(b)(23)) are subject to PSD review. Among other things, PSD review requires those pollutants that will be emitted at levels greater than the significant level to be controlled using BACT. Potential emissions from the proposed facility are summarized in Table 2-1, along with the corresponding PSD significant emission rate.

[2] Detailed emission calculations for each source are summarized in Section 3.0 of the Deer Creek PSD Permit Application.

Best Available Control Technology

Table 2-1
PSD Significant Emission Levels

Pollutant	Significant Emission Rate (tpy)	Deer Creek Potential Emission (tpy)	Subject to PSD Review (y/n)
Carbon Monoxide (CO)	100	256.0	y
Nitrogen Oxides (NOx)	40	119.1	y
Sulfur Dioxide (SO_2)	40	11.7	n
Particulate Matter (PM)	25	80.1	y
PM_{10}	15	80.1	y
$PM_{2.5}$	10	80.1	y
Ozone (VOC or NOx)	40	29.7	n
Lead	0.6	3.60×10^{-4}	n
Sulfuric Acid Mist	7	2.21	n

Based on emission calculations, the proposed Deer Creek Station is subject to PSD review for NOx, CO, and particulate matter (PM, PM_{10}, and $PM_{2.5}$). Emissions of NOx, CO, and PM must be controlled using technologies that represent BACT. The top-down BACT methodology described above will be applied for the control of NOx, CO, and PM from the following emission sources:

- Natural Gas Combined Cycle (CT & HRSG)
- Diesel-Fired Emergency Generator
- Diesel-Fired Fire Water Pump
- Emergency Inlet Air Heater

3.0 BACT ANALYSIS FOR COMBUSTION TURBINE NOx CONTROL

3.1 Step 1: Identify Potentially Feasible NOx Control Options

Potentially available control options were identified based on a comprehensive review of available information. NOx control technologies with potential application to the Deer Creek NGCC are listed in Table 3-1.

Table 3-1
List of Potential NOx Control Options

Control Technology
Combustion Controls
Water/Steam Injection
Dry Low NOx Combustion
Post-Combustion Controls
Selective Catalytic Reduction (SCR)
SCR with Ammonia Oxidation Catalyst (Zero-Slip™)
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)
Urea Injection Systems (Selective Non-Catalytic Reduction and NOxOut™)
Ammonia Injection Systems (Thermal DeNOx™)
Catalytic Combustion (Xonon™)

3.2 Step 2: Technical Feasibility of Potential NOx Control Options

NOx control technologies can be divided into two general categories: combustion controls and post-combustion controls. Combustion controls reduce the amount of NOx that is generated in the combustion turbine or duct burner. Post-combustion controls remove NOx from the combustion turbine exhaust gas.

Best Available Control Technology

3.2.1 Combustion Controls

NOx formation in a natural gas-fired combustion turbine (CT) occurs by three fundamentally different mechanisms; thermal NOx, prompt NOx, and fuel NOx. Prompt NOx is formed from reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NOx forms within the flame and is usually negligible when compared to thermal NOx. Fuel NOx is formed by the gas-phase oxidation of fuel-bound nitrogen compounds with oxygen. Its formation is dependent on fuel nitrogen content and the combustion oxygen levels. Natural gas contains negligible chemically-bound fuel nitrogen; thus, the formation of fuel NOx is also negligible when compared to thermal NOx.

Essentially all NOx formed from natural gas combustion is thermal NOx. Thermal NOx is created by the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. The amount of thermal NOx formed is a function of the combustion chamber design and the CT operating parameters, including flame temperature, residence time at flame temperature, combustion pressure, and fuel/air ratios at the primary combustion zone. The maximum thermal NOx formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The rate of thermal NOx formation is also an exponential function of the flame temperature. Uncontrolled NOx emissions from a natural gas-fired combustion turbine will be in the range of 0.32 lb/mmBtu (or approximately 90 ppmvd @ 15% O_2).[3]

3.2.1.1 Water/Steam Injection

Injection of water or steam into the high temperature zones of the combustion turbine flame is a combustion control technique that can be used to reduce the formation of thermal NOx. NOx reduction will be a function of the combustor design and the water-to-fuel ratio employed. Although water/steam injection will reduce the formation of NOx, positioning of the injection is not precise and some NOx is still created. Water or steam injection systems have demonstrated the ability to achieve controlled NOx emissions of approximately 35 ppmvd @ 15% O_2, or 0.13 lb/mmBtu.

In order to avoid corrosion and the formation of deposits in the turbine expansion section, thoroughly demineralized water needs to be used for either approach. Water or steam

[3] See, AP-42 Table 3.1-1 Emission Factors for NOx and CO from Stationary Gas Turbines.

injection can also increase CO emissions as temperatures in the burnout zone are lowered. Water or steam injection control systems are also accompanied by an efficiency penalty in the range of 2 to 3%, but an increase in power output of 5 to 6%. The increased power output results from the increase mass flow required to maintain the turbine inlet temperatures. Finally, water/steam injection cannot be used when firing natural gas with dry-low NOx combustors.

For this BACT analysis it was concluded that either water or steam injection could be used to control CT NOx formation in the Deer Creek CT, and that either combustion control system could achieve a controlled NOx emission rate of 35 ppmvd @ 15% O_2 (30-day average). However, water/steam injection systems are not as effective at controlling NOx as dry-low NOx combustors, and cannot be used in conjunction with dry-low NOx combustors. Water/steam injection also reduces the efficiency of the combustion turbine, and results in increased CO emissions. Because water/steam injection control systems are not as effective at dry-low NOx combustors, water/steam injection NOx control systems will not be evaluated further in this BACT analysis.

3.2.1.2 Dry Low-NOx Combustion

Excess air in lean combustion cools the flame and reduces the formation of thermal NOx. Dry low-NOx (DLN) combustion systems reduce the amount of thermal NO_X formed by lowering the overall flame temperature within the CT combustor. The lower flame temperature is accomplished by premixing the fuel and air at controlled stoichiometric ratios prior to combustion.

Prior to the development of premix-based DLN combustors, fuel and air were injected separately into the CT's combustor section. Oxygen in the combustion air, needed to support the combustion process, would diffuse into the flame front located at the combustor's fuel burner, and combustion occurred in a diffusion flame. The result of this approach was a range of fuel-to-air ratios over which combustion occurred and a corresponding range of flame temperatures.

For DLN combustor designs, air/fuel mixing is accomplished prior to the burner where the actual combustion occurs. This design provides better control of the air-to-fuel stoichiometric ratio, lower flame temperature, reduced excess oxygen, and minimizes the potential for localized high-temperature fuel-rich pockets.

Best Available Control Technology

DLN combustion is a technically feasible and commercially available NOx control system for the Deer Creek CT. Emission guarantees available from burner manufacturers vary, and will depend on the test method used to demonstrate compliance, averaging time, combustion turbine load, load cycling, and burner tuning. Based on information available from burner vendors, emission guarantees in the range of approximately 9 ppmvd @ 15% O_2 to 25 ppmvd @ 15% O_2 should be available for loads above 50% under new and clean conditions. Below 50% load controlling the combustion process becomes more difficult and NOx emissions will tend to fluctuate.

Duct firing will increase NOx emissions from the NGCC unit (lb/hr), but should not increase the NOx rate (ppmvd or lb/mmBtu total heat input). Duct burners are direct-fired gas burners located in the turbine exhaust stream, and controlling combustion conditions within this environment can be challenging. Combustion conditions within the HRSG will vary depending on exhaust gas temperature and velocity, uniformity of the exhaust gas flow, and the exhaust gas oxygen and moisture content. Combustion controls installed on the combustion turbine can also make combustion in the HRSG more difficult. More efficient turbines fire to higher exhaust gas temperatures with lower oxygen and higher water content. Burner controls designed to reduce NOx emissions tend to further reduce oxygen levels in the combustion turbine exhaust gas.

Exhaust gas flow velocity and uniformity of the flow are also important variables associated with lower emission duct firing. Eddies and localized areas of high or low flow can cause flames to impinge on burner parts or sidewalls. Distribution grids and flow straightening vanes may be used in expanding ducts to achieve the required flow profile across the burners. Flow baffles may also be required to increase the combustion turbine exhaust gas velocity across the burners for optimum combustion and emission performance. Based on information obtained from duct burner vendors, NOx emissions associated with the most recently available low-NOx duct burner designs will be limited to approximately 15 ppmvd @ 15% O_2, or approximately 0.055 lb/mmBtu (heat input to the duct burner). This emission rate is similar to the emission rate achieved with combustion controls on the combustion turbine.

Combustion controls are a technically feasible and commercially available NOx control system. Based on information from burner vendors and emissions achieved in practice at similar sources, low-NOx combustion on the CT and duct burners will be evaluated at a controlled NOx emission rate of 15 ppmvd @ 15% O_2 (30-day average). A controlled NOx emission rate of 15 ppmvd @ 15% O_2 is equivalent to an emission rate of approximately 0.055 lb/mmBtu total heat input. Achieving this emission rate on a continuous basis will require proper tuning, operation, and maintenance of the burners, while providing a reasonable margin to account for normal system fluctuations.

3.2.2 Post-Combustion NOx Controls

A second general strategy to minimize NOx emissions from a natural gas-fired combined cycle unit is to reduce NOx formed in the CT/HRSG using a post-combustion control system. Potentially available post-combustion NOx control systems are evaluated below. Post-combustion control systems will be evaluated assuming the CT will be designed with dry-low NOx burner combustion controls.

3.2.2.1 Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion NOx control technology. SCR reduces NOx by injecting ammonia (NH_3) in the presence of a catalyst. Ammonia reacts with NOx in the presence of active catalyst and excess oxygen to form water vapor and nitrogen, as shown in the following equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The performance of an SCR system is influenced by several factors including flue gas temperature, SCR inlet NOx level, the catalyst surface area, volume and age of the catalyst, and the amount of ammonia slip that is acceptable.

SCR catalysts used in combined cycle application generally consist of a noble metal (e.g., platinum), base metal oxide (e.g., vanadium oxide mixed with titanium dioxide as a substrate). Metal based catalysts are generally applied as a coating over a metal or ceramic substrate. For high temperature applications (approximately 1,100 ^oF), such as simple cycle combustion turbines, zeolite catalysts are available. Zeolite catalysts are typically a homogeneous material that forms both the active surface and substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the gas turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit.

Flue gas temperature and residence time must be taken into consideration when designing a SCR control system. The temperature range for base metal catalyst is in the range of 400 ^{o}F and 800 ^{o}F. On a combined-cycle combustion turbine, this temperature window occurs within the heat recovery steam generator (HRSG), downstream of the gas turbine.

Controlled NOx emission rates achievable with a SCR control system are a function of the catalyst volume, ammonia-to-NOx (NH_3:NOx) ratio, reaction temperature, and catalyst activity. For a given catalyst volume, higher NH_3:NOx ratios can be used to achieve higher NOx emission reductions, but this control strategy can result in an unacceptable increase in emissions of unreacted NH_3 (ammonia slip).

Catalyst activity is a function of catalyst age and deactivation. SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation (catalyst sintering) if the catalyst is exposed to excessive temperatures (typically > 800 ^{o}F) over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include compounds containing arsenic, sulfur, potassium, sodium, and calcium. On a natural-gas combined cycle unit, where only natural gas is fired, potential catalyst poisons should be minimal, and a catalyst life of approximately 5 years can be expected.

Ammonia slip should be minimized due to the potential for salt formation from the reaction of ammonia with sulfur compounds in the flue gas. The combustion of sulfur-bearing fuels produces SO_2 , and to a lesser degree SO_3. Some conversion of SO_2 to SO_3 also occurs across the SCR catalyst bed. SO_3 in the flue gas can react with ammonia to form ammonium sulfate and/or ammonium bisulfate. Ammonium bisulfate is a sticky compound, which can deposit in the low-temperature region of the HRSG, resulting in increased back-pressure on the CT and reduced heat transfer efficiency in the HRSG. A unit shutdown is generally required to remove ammonium bisulfate deposits from heat transfer surfaces.

The rate of ammonium salt formation increases with increasing levels of SO_3 and NH_3, and decreasing stack gas temperature. Ammonium sulfate and bisulfate are also classified as condensable particulates; thus, the formation of ammonium salts results in an increase in

Best Available Control Technology

PM10 emissions. Because the Deer Creek NGCC will fire natural gas exclusively, these issues should be minimal; however, to minimize potential operating issues and to minimize ammonia and condensible particulate emissions, ammonia slip should still be maintained below a level of approximately 5 ppmvd.

SCR is considered a technically feasible and commercially available NOx control technology for the Deer Creek NGCC. SCR control has been installed on natural gas-fired NGCC units, and has demonstrated the ability to effectively reduce NOx emissions. Based on a review of emission rates achieved in practice at similar sources and emission limits included in recently issued PSD permits for natural gas-fired NGCC facilities, it is concluded that an SCR control system could be designed to achieve a controlled NOx emission rate of 3.5 ppmvd @ 15% O_2 (30-day average). A controlled NOx emission rate of 3.5 ppmvd @ 15% O_2 should be achievable over the life of the catalyst and while maintaining acceptable ammonia slip.

3.2.2.2 SCR with Ammonia Oxidation Catalyst (Zero-Slip™)

To address potential collateral environmental impacts associated with ammonia slip from SCR control, one vendor is developing a control technology designed for simultaneous control of NOx and ammonia emissions. The Zero-Slip™ system consists of a layer of conventional SCR catalyst followed by Zero-Slip™ catalyst. Ammonia, injected into the flue gas through an injection grid upstream of the SCR catalyst, flows through the SCR and Zero-Slip™ catalysts. The Zero-Slip™ catalyst consists of layers of both ammonia oxidation and denitration catalyst designed to reduce NOx emissions while achieving near zero ammonia slip, as shown in the following equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 5O_2 \rightarrow 4N_2 + 6H_2O$$

This technology was originally developed by Mitsubishi Heavy Industries and is being jointly demonstrated by Cormetech and Mitsubishi Power Systems.

This technology should be capable of achieving controlled NOx emission rates similar to those achievable with SCR. Potential advantages of this control technology, compared to other SCR control systems, include achieving low NOx emissions with lower ammonia slip. Full-scale operation of the technology on a 7.5 MW Solar Taurus turbine has demonstrated the technology's ability to achieve SCR-level NOx emissions (i.e., less than approximately 5 ppmvd @ 15% O_2) with ammonia slip less than 1.0 ppm.

To date, commercial demonstration of Zero-Slip™ has been limited to smaller scale combustion turbines, and the technology has not been demonstrated on larger utility size natural gas-fired turbines. It is likely that BEPC would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system at the Deer Creek Station. BACT does not require applicants to experience extended time delays or resource penalties to allow research to be conducted on an emerging control technique. Therefore, at this time, Zero-Slip™ will not be evaluated as an independent control technology, but will be included in the evaluation of SCR control systems.

3.2.2.3 Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)

EMx™ is a post-combustion, multi-pollutant control technology, originally developed by Goal Line Environmental Technologies (now EmeraChem LLC). The EMx™ technology uses a coated oxidation catalyst to remove NOx, CO, and VOC emissions in the turbine exhaust gas by oxidizing CO to CO_2, NO to NO_2, and hydrocarbons to CO_2 and water. The CO_2 is then emitted to the atmosphere, and the NO_2 is absorbed onto the potassium carbonate coating on the EMx™ catalyst to form potassium nitrate/nitrite. These reactions are referred to as the "oxidation/absorption cycle."

Because the potassium carbonate coating is consumed as part of the absorption step, it must be regenerated periodically. This is accomplished by passing a regeneration gas containing hydrogen and carbon dioxide across the surface of the catalyst in the absence of oxygen. The hydrogen in this gas reacts with nitrites and nitrates to form water vapor and elemental nitrogen. The carbon dioxide in the gas reacts with the liberated potassium oxide to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began. These reactions are called the "regeneration cycle." Water vapor and elemental nitrogen are exhausted, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to repeat.

Best Available Control Technology

Because the regeneration cycle must take place in an oxygen-free environment, the catalyst undergoing regeneration must be isolated from the CT-HRSG exhaust gas. This is accomplished by dividing the catalyst bed into discreet sections, and placing dampers upstream and downstream of each section. During regeneration, some of the dampers close, isolating a section of the catalyst bed. While this is going on, exhaust gas continues to flow through the remaining open sections of the catalyst bed. After the isolated section of catalyst has been regenerated, another set of dampers closes so that the next section of catalyst can be isolated for regeneration. This cycle is repeated for each catalyst section approximately once every 5 minutes.

The EMx™ catalyst is very sensitive to fouling, because the potassium coating is irreversibly deactivated by sulfur in the exhaust gas. For large-scale applications, however, EmeraChem recommends using a sulfur oxidation/absorption catalyst, called ESx™ (formerly SCOSOx), to remove sulfur from the exhaust gas. The ESx™ catalyst would be located upstream of the EMx™ catalyst, and would be regenerated at the same time as the EMx™ catalyst. Regeneration of the ESx™ catalyst would result in an off-gas consisting of H_2S and/or SO_2. The H_2S/SO_2 off-gas would be discharged to the HRSG stack and emitted into the atmosphere.

The EMx™ multi-pollutant control system has operated successfully on several smaller natural gas-fired units. Potential advantages of the EMx™ control system include the concurrent control of CO and VOC emissions and the fact that the control system does not use a reactant. However, there are a number of engineering challenges associated with applying this technology to larger plants with full scale operations such as the Deer Creek Project. Potential issues include the following:

- For large-scale NGCC applications, the EMx™ catalyst would have to be placed in the HRSG where the exhaust gas temperatures will be in the range of 500 to 700 °F. Performance of the EMx™ catalyst in a high-temperature application has not been demonstrated in practice.

- The dampers and damper bearings, which are moving parts exposed to the hot exhaust gas, could present long-term maintenance and reliability problems. This is particularly true as the damper size and number of dampers increase, as would be necessary in order to use this technology for Deer Creek.

- Regeneration of the EMx™ catalyst would require hydrogen gas to be continuously generated (from natural gas) and introduced into the high-temperature zone of the

Best Available Control Technology

HRSG. Because hydrogen gas is explosive, any leaks in the dampers used to isolate the catalyst for regeneration could create a serious hazard.

- In addition to periodic regeneration, the EMx™ catalyst would have to be cleaned at least once per year by removing the catalyst beds from the HRSG and dipping them in a potassium carbonate solution.
- The EMx™ and ESx™ processes have the potential to create additional air pollutants, such as hydrogen sulfide (H_2S). Emissions of these additional pollutants have not been completely quantified.

To date, the EMx™ (SCONOx) multi-pollutant control system has not been installed and operated on a large NGCC application. It is likely that BEPC would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system at the Deer Creek Station. BACT does not require applicants to experience extended time delays or resource penalties to allow research to be conducted on an emerging control technique. Therefore, at this time the EMx™ control system is not considered an available NOx control system, and will not be further evaluated in the BACT analysis.

3.2.2.4 Urea Injection Systems (Selective Non-Catalytic Reduction and NOxOut™)

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) at flue gas temperatures of approximately 1600 - 1900 ºF. The ammonia or urea reacts with NOx in the flue gas to produce N_2 and water. The NOx reduction reactions in an SNCR are driven by the thermal decomposition of ammonia or urea and the subsequent reduction of NOx. SNCR systems do not employ a catalyst to promote these reactions.

Flue gas temperature at the point of reagent injection can greatly affect NOx removal efficiencies and the quantity of reactant that will pass through the SNCR unreacted (e.g., slip). At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted reactant emissions increase. Above the desired temperature range, the reactant may be oxidized to NOx resulting in low NOx reduction efficiencies.

The NOxOut™ process is a post-combustion NOx reduction method in which aqueous urea is injected into the flue gas stream. The urea reacts with NOx in the flue gas to produce N_2 and water as shown below:

Best Available Control Technology

$$(NH_2)_2CO + 2NO + \frac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

The use of urea to control NOx emissions was developed under the sponsorship of the Electric Power Research Institute (EPRI). The urea-NOx reaction takes place over a narrow temperature range, below which ammonia is formed and above which NOx emission levels may actually increase. Fuel Tech's NOxOut™ process is a urea-based SNCR process that uses mechanical modifications and chemical injection hardware to widen the effective temperature range of the reaction to between 1,600 and 1,950 ^{o}F.

Based on information available from the vendor, the NOxOut™ process has been demonstrated on a 90 MW GE Frame 7EA gas turbine at a combined cycle cogeneration facility, and was able to achieve a controlled NOx emission rate of 5 ppm. Potential advantages of the system include lower slip levels (compared to other SNCR designs), no catalyst, and lower capital and operating costs (compared to SCR). Potential disadvantages of the system include ammonia emissions due to excess urea injection, ammonia reacting with SO3to form ammonium salts, and potential increase in NOx emissions if exhaust gas temperatures are too high. To date, commercial application of this system on large natural gas-fired combined cycle units has been limited.

Based on a review of available literature, and engineering judgment, the NOxOut™ process is not considered a technically feasible NOx control option for the Deer Creek NGCC. NOx reduction reactions require flue gas temperatures in the range of 1,600 to 1,950 ^{o}F; however, exhaust gas temperatures from the Deer Creek combustion turbine will be in the range of 1,100 ^{o}F. Increasing the exhaust gas temperature would significantly reduce the efficiency of the combustion turbine or require additional fuel consumption and installation of a flue gas heater. Neither option is considered practical for a NGCC unit. Therefore, at this time, NOxOut™ is not considered a technically feasible NOx control option for Deer Creek, and will not be considered further in this BACT analysis.

3.2.2.5 Ammonia Injection Systems (Thermal DeNOx™)

Exxon Research and Engineering Company's Thermal DeNOx™ process utilizes an ammonia/NOx SNCR reaction to reduce NOx to nitrogen and water as shown in the following equation:

Best Available Control Technology

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

Hamon Research Cottrell is licensed by Exxon-Mobil for the application of the ammonia-based Thermal DeNOx™ process. The process consists of a high-temperature selective non-catalytic reduction of NOx using ammonia as the reducing agent. This process does not use a catalyst to aid the reaction, rather temperature control is used to direct the reactions. Optimum reaction temperatures for NOx reduction are between 1,600 ^{o}F and 1,800 ^{o}F. Below the optimum temperature range, ammonia does not fully react and can be released in the flue gas. Above the optimum temperature, the following competing reaction will begin to take place, which can result in increased NOx emissions:

$$4H_3 + 5O_2 \rightarrow 4O + 6H_2O$$

To date, commercial applications of the Thermal DeNOx™ process have been limited to furnaces, heavy industrial boilers, and incinerators that consistently produce exhaust gas temperatures in the range of 1,800 ^{o}F consistently. Because exhaust gas volumes increase significantly with increased temperatures, application of the Thermal DeNOx™ process would require that flue gas handling systems be designed to handle larger high temperature flows. Similar to the NOxOut™ process, high capital and O&M costs are expected due to material requirements, additional equipment, and fuel consumption. It is likely that BEPC would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system at the Deer Creek Station. BACT does not require applicants to experience extended time delays or resource penalties to allow research to be conducted on an emerging control technique. Therefore, at this time the Thermal DeNOx™ control system is not considered an available NOx control system, and will not be further evaluated in the BACT analysis.

3.2.2.6 Catalytic Combustion (Xonon™)

Catalytic combustion uses a catalyst within the combustor to oxidize a lean air-to-fuel mixture rather than burning with a flame. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NOx. One technical challenge associated with catalytic combustion has been achieving catalyst life long enough to make the combustor commercially viable.

Best Available Control Technology

The Xonon™ ("no NOx" spelled backwards) combustion system was originally developed by Catalytica Combustion Systems (now Catalytica Energy Systems). The Xonon™ control system works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is lower temperature partial combustion followed by flameless catalytic combustion to reduce NOx formation.

To date, the system has successfully completed pilot- and full-scale testing, and has been demonstrated on a 1.5 MW Kawasaki gas turbine. However, the Xonon™ combustion system has not been demonstrated for extended periods of time on a large natural gas-fired combustion turbine. Applications of this technology have been in the 1 to 15 MW range. It is likely that BEPC would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system at the Deer Creek Station. BACT does not require applicants to experience extended time delays or resource penalties to allow research to be conducted on an emerging control technique. Therefore, at this time, catalytic combustion systems (including Xonon™) are not considered available NOx control systems, and will not be further evaluated in the BACT analysis.

The results of Step 2 of the NOx BACT Analysis (technical feasibility analysis of potential NOx control technologies) are summarized in Table 3-2.

Table 3-2
Technical Feasibility of Potential NOx Control Technologies

Control Technology	Controlled NOx Emission Rate* ppmvd @ 15% O_2	In Service on Existing NGCC Units		Technically Feasible on the Deer Creek NGCC Unit?
		Yes	No	
Water/Steam Injection	35	X		Yes
Dry Low NOx Combustion	15	X		Yes
Selective Catalytic Reduction (SCR)	3.5	X		Yes
SCR with Ammonia Oxidation Catalyst (Zero-Slip™)	NA	X (limited application)		The SCR portion of the control system is considered technically feasible; however, the ammonia oxidation system has not been demonstrated in practice on a large natural gas-fired combustion turbine and is not considered commercially available for the Deer Creek NGCC unit.
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)	NA	X (limited application)		This control technology has not been demonstrated on a large natural gas-fired NGCC, and, at this time, is not considered technically feasible or commercially available for the Deer Creek NGCC unit.
Urea Injection Systems (Selective Non-Catalytic Reduction and NOxOut™)	NA	X (limited application)		This control technology has not been demonstrated on a large natural gas-fired NGCC, and, at this time, is not considered technically feasible or commercially available for the Deer Creek NGCC unit.
Ammonia Injection Systems (Thermal DeNOx™)	NA	X (limited application)		This control technology has not been demonstrated on a large natural gas-fired NGCC, and, at this time, is not considered technically feasible or commercially available for the Deer Creek NGCC unit.
Catalytic Combustion (Xonon™)	NA	X (limited application)		This control technology has not been demonstrated on a large natural gas-fired NGCC, and, at this time, is not considered technically feasible or commercially available for the Deer Creek NGCC unit.

*Emission rates included in this table represent enforceable permit limits that should be achievable under all normal operating conditions based on a 30-day rolling average period.

Best Available Control Technology

3.3 Step 3: Rank the Technically Feasible NOx Control Options by Effectiveness

The technically feasible and commercially available NOx control technologies are listed in Table 3-3 in descending order of control efficiency.

Table 3-3
Technical Feasibility of Potential NOx Control Technologies

Technology	Controlled NOx Emission Rate (ppmvd @ 15% O_2)*
Water/Steam Injection Control	35
Dry Low-NOx Combustion	15
Selective Catalytic Reduction	3.5

*NOx emission rates shown in this table represent controlled emission rates that should be achievable based on a 30-day rolling average.

3.4 Step 4: Evaluate the Technically Feasible NOx Control Technologies

3.4.1 NOx Control Technologies – Economic Evaluation

The most effective NOx control system, in terms of reduced emissions, that is considered to be technically feasible for the proposed NGCC unit consists of combustion controls and post-combustion SCR. This combination of controls should be capable of achieving the most stringent controlled NOx emission rate on an on-going long-term basis. The effectiveness of the SCR system is dependent on several site-specific system variables, including the size of the SCR (i.e., number of catalyst layers), NH_3/NOx stoichiometric ratio, acceptable NH_3 slip, and catalyst deactivation rate. Based on emission rates achieved in practice at similar sources, and including a reasonable margin to account for normal system fluctuations and long-term SCR operation, the combination of combustion controls and SCR should achieve a controlled NOx emission rate of 3.5 ppmvd @ 15% O_2 (approximately 0.013 lb/mmBtu) on a 30-day rolling average.

BEPC is proposing SCR as BACT for NOx control from the Deer Creek NGCC unit. Because BEPC is proposing to use the control technology that will achieve the most stringent NOx control (i.e., the lowest emission rate), no economic evaluation of the alternative NOx control systems is required.[4]

3.4.2 NOx Control Technologies – Environmental Impacts

Combustion modifications designed to decrease NOx formation (i.e., lower temperatures and less oxygen availability) also tend to increase the formation and emission of CO and VOCs. Combustion controls, including dry low-NOx burners, need to be designed to reduce the formation of NOx while maintaining CO and VOC formation at acceptable levels. Other than the NOx/CO-VOC trade-off, there are no environmental issues associated with using combustion controls to reduce NOx emissions from a natural gas-fired combustion turbine.

Operation of an SCR system has certain collateral environmental consequences. First, in order to maintain low NOx emissions some excess ammonia will pass through the SCR. Ammonia slip will increase as NOx emissions are driven lower, and will tend to increase as the catalyst becomes deactivated. Ammonia slip from an SCR designed to achieve a controlled NOx emission rate of 3.5 ppmvd @ 15% O_2 (30-day average) on a natural gas-fired combustion turbine is expected to be in the range of 2 ppm or less during initial operation. As the catalyst ages and becomes deactivated, ammonia slip can increase; however, the ammonia slip rate is not expected to exceed 5 ppm under normal operating conditions.

Second, undesirable reactions can occur in an SCR system, including the oxidation of NH_3 and SO_2 and the formation of ammonium sulfate salts. A fraction of the SO_2 in the flue gas (approximately 4%) will oxidize to SO_3 in the presence of the SCR catalyst. SO_3 can react with water to form sulfuric acid mist or with the ammonia slip to form ammonium sulfate or ammonium bisulfate. Sulfuric acid mist and ammonium sulfate are classified as condensable particulates; thus, SCR control can result in increased PM10 emissions. Although the formation of condensible particulates will increase with SCR control, natural gas is a low-sulfur fuel; therefore, the increase in condensable particulates will be minimal. Based on emission calculations, SCR at an ammonia slip of 5 ppm will increase condensible PM10 emissions by approximately 0.32 lb/hr (or potentially 1.4 tpy). This increase in condensible PM10 is not considered significant enough as to preclude the use of an SCR system to control NOx emissions.

[4] See, New Sour Review Manual, page B.35.

Finally, the storage of ammonia on-site increases the risks associated with an accidental ammonia release. Depending on the type, concentration, and quantity of ammonia used, ammonia storage/handling will be subject to regulation as a hazardous substance under CERCLA, Section 313 of the Emergency Planning and Community Right-to-Know Act, Section 112(r) of the Clean Air Act, and Section 311(b)(4) of the Clean Water Act.

Although there are collateral environmental issues associated with using an SCR system, the issues are not of such a magnitude as to preclude the use of an SCR system to control NOx emissions.

3.4.3 NOx Control Technologies – Energy Impacts

Post-combustion SCR NOx control requires auxiliary power. Auxiliary power requirements associated with SCR include power for the ammonia handling and injection system as well as additional fan power to overcome pressure drop through SCR vessel. Based on engineering calculations, pressure drop through the SCR will be in the range of approximately 4 to 5 in. w.c. Assuming 220 kW/inch auxiliary power requirement, and a power cost of $60/MWh, auxiliary power costs for the SCR control system will be in the range of $500,000/year. Although these costs are significant, BEPC has concluded that SCR represents BACT for NOx control, and that potential economic and energy impacts are not so significant as to exclude SCR from consideration as BACT.

A summary of the Step 4 economic, environmental, and energy impact analysis is provided in Table 3-4.

Table 3-4
Summary of NOx BACT Impact Analysis

Control Technology	Controlled NOx Emission Rate* ppmvd @ 15% O_2	Annual NOx Emissions (tpy)*	Economic Impacts: Average Cost Effectiveness ($/ton removed)	Environmental and Energy Impacts
Water/Steam Injection Control	35	not calculated	Not Evaluated BEPC is proposing to use the most effective NOx control technology as BACT; therefore, no economic evaluation of the alternative NOx control systems is required.	No significant collateral environmental impacts.
Dry Low-NOx Combustion	15	455.2		Combustion controls designed to minimize NOx formation (i.e., lower temperatures and less excess O_2) can result in increased CO and VOC emissions.
Selective Catalytic Reduction	3.5	116.6		Potential collateral environmental impacts include increased SO_2 to SO_3 oxidation, increased condensible particulate emissions, ammonia emissions, and ammonia storage and handling issues. The SCR control system will also require auxiliary power to run the ammonia handling and injection system and to overcome pressure drop across the SCR

* Annual emissions were calculated based on a full load combustion turbine operation at annual average ambient conditions without duct firing for approximately 5,852 hours per year, full load operation with duct firing for 2,200 hours per year, and estimated startup/shutdown emissions for approximately 708 hours per year. Detailed emission calculations are included in Appendix B of the Deer Creek PSD Permit Application.

3.5 Step 5: Select BACT for NOx Control

Based on the foregoing control technology evaluation, BACT evaluations included in recently submitted PSD permit applications for similar sources, and BACT limits included in recently issued PSD permits (Attachment A), it is concluded that a combination of low-NOx combustion followed by SCR represents BACT for NOx control for the proposed Deer Creek NGCC unit. Based on emission rates achieved in practice at similar sources, and including a reasonable margin to account

Best Available Control Technology

for normal system fluctuations and long-term SCR operation, the combination of combustion controls and SCR should achieve a controlled NOx emission rate of 3.5 ppmvd @ 15% O_2 (30-day average). A controlled NOx emission rate of 3.5 ppmvd @ 15% O_2 (approximately 0.013 lb/mmBtu) should be achievable over the life of the catalyst and while maintaining acceptable ammonia slip and minimizing potential collateral environmental impacts. Achieving this emission limit will require the facility to properly operate and maintain the burners as well as the SCR control system on a continuous on-going basis.

Best Available Control Technology

4.0 BACT ANALYSIS FOR COMBUSTION TURBINE CO CONTROL

Emissions of carbon monoxide (CO) result from incomplete fuel combustion. CO is formed from the partial oxidation of fuel carbon. Factors that influence CO formation include improper fuel-to-air ratios, inadequate fuel mixing, inadequate combustion temperatures, and reduced excess O_2. Combustion turbine operation at lower loads (below approximately 50%) can also affect combustion controls and the formation of CO.

In natural gas-fired combustion turbines, combustion controls designed to minimize NOx formation, including sub-stoichiometric combustion and reduced peak combustion temperatures, can increase the formation of CO. NOx control methods such as lean premix combustion, low flame temperature, and water/steam injection can increase CO. Combustors can be designed to minimize the formation of CO while reducing the peak combustion temperature and NOx emissions.

4.1 Step 1: Identify Potentially Feasible CO Control Options

Potentially available control options were identified based on a comprehensive review of available information. CO control technologies with potential application to the Deer Creek NGCC are listed in Table 4-1.

Table 4-1
List of Potential CO Control Options

Control Technology
Combustion Controls
Dry Low NOx Combustion
Post-Combustion Controls
Oxidation Catalyst
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)
Catalytic Combustion (Xonon™)

Best Available Control Technology

4.2 Step 2: Technical Feasibility of Potential CO Control Options

CO control technologies can be divided into two general categories: combustion controls and post-combustion controls. Combustion controls reduce the amount of CO generated in the combustion turbine or duct burner. Post-combustion controls remove CO from the combustion turbine exhaust gas.

4.2.1 Combustion Controls

As discussed in section 3.2.1 combustion controls designed to minimize NOx formation, including lower peak combustion temperatures and less excess oxygen, tend to increase the formation of CO emissions. Burner vendors attempt to address these issues by improving fuel-air mixing and ensuring adequate residence times within the combustion zone. Improved mixing will minimize the potential for fuel-rich areas and the resulting formation of CO. Increased residence time within the combustion zone provides the oxygen needed for more complete oxidation.

A properly designed and operated combustion turbine effectively functions as a thermal oxidizer. CO formation is minimized when combustion turbine temperature and excess oxygen availability are adequate for complete combustion. Minimizing CO emissions is also in the economical best interest of the combustion turbine operator because CO represents unutilized energy exiting the process. Based on information available from burner vendors, the dry-low NOx burners proposed for the Deer Creek NGCC should be able to maintain an average CO concentration of 9.0 ppmvd (approximately 7.4 ppmvd @ 15% O_2) while limiting average NOx emissions to 15 ppmvd @ 15% O_2. A CO concentration of 9.0 ppmvd is equivalent to an emission rate of approximately 0.017 lb/mmBtu heat input.

Duct firing tends to increase CO emissions from the NGCC unit. Duct burners are direct-fired gas burners located in the turbine exhaust stream, and controlling combustion conditions within this environment can be challenging. Combustion conditions within the HRSG will vary depending on exhaust gas temperature and velocity, uniformity of the exhaust gas flow, and the exhaust gas oxygen and moisture content. Combustion controls installed on the combustion turbine can also make combustion in the HRSG more difficult. More efficient turbines fire to higher exhaust gas temperatures with lower oxygen and higher water content. Burner controls designed to reduce NOx emissions tend to further reduce oxygen levels in the combustion turbine exhaust gas.

Exhaust gas flow velocity and uniformity of the flow are also important variables associated with lower emission duct firing. Eddies and localized areas of high or low flow can cause flames to impinge on burner parts or sidewalls. Distribution grids and flow straightening vanes may be used in expanding ducts to achieve the required flow profile across the burners. Flow baffles may also be required to increase the combustion turbine exhaust gas velocity across the burners for optimum combustion and emission performance. Based on information obtained from duct burner vendors, CO emissions associated with the most recently available low-NOx duct burner designs can be limited to 0.05 lb/mmBtu (heat input to the duct burner) while maintaining NOx emissions at approximately 15 ppmvd @ 15% O_2.

Combustion controls are a technically feasible method of controlling CO emissions from the proposed Deer Creek combustion turbine and duct burners. Proper burner design and operation can minimize NOx emissions, while maintaining CO at acceptable levels. Based on information available from burner vendors, the dry-low NOx burners proposed for the Deer Creek NGCC should be able to maintain an average CO concentration of 9.0 ppmvd (7.4 ppmvd @ 15% O_2) while limiting average NOx emissions to 15 ppmvd @ 15% O_2. CO emissions associated with duct firing will be limited to 0.05 lb/mmBtu (heat input to the duct burner). Based on emission calculations at full load heat input to the boiler and maximum duct firing (annual average ambient conditions), duct firing will increase CO emissions in the exhaust from 9.0 to 18.3 ppmvd (or approximately 0.025 lb/mmBtu total heat input to the CT and duct burner).[5]

4.2.2 Post-Combustion CO Controls

A second general strategy to minimize CO emissions from a natural gas-fired combined cycle unit is to reduce CO using post-combustion controls. Potentially available post-combustion CO control systems are evaluated below. Post-combustion control systems will be evaluated assuming the combustion turbine and duct burners are designed with low NOx combustion.

4.2.2.1 Oxidation Catalyst

Catalytic oxidation systems are designed to oxidize CO to CO_2. Catalytic oxidation is a post-combustion technology which reduces CO emissions without the addition of chemical

[5] Detailed emission calculations are provided in Appendix B of the Deer Creek PSD Permit Application.

reagents. The oxidation catalyst, typically consisting of a noble metal, promotes the oxidation of CO at temperatures approximately 50% below the temperature required for oxidation without the catalyst. The operating temperature range for commercially available CO oxidation catalysts is between 650 and 1,150 ^oF. On a natural gas-fired combined cycle unit this temperature window occurs within the HRSG. On units equipped with an SCR, the oxidation catalyst system would be installed in the HRSG immediately upstream of the SCR.

Oxidation catalyst efficiency varies with inlet CO concentration, inlet gas temperature, and flue gas residence time. In general, removal efficiency will increase with increased flue gas temperatures and increased catalyst bed depth. Bed depth will be limited by pressure drop across the catalyst, and by the location of the SCR within the HRSG.

Catalytic oxidation systems have been installed on natural gas-fired combined cycle units, and have demonstrated the ability to effectively reduce CO emissions. In natural gas-turbine applications, catalytic oxidation systems have demonstrated the ability to achieve controlled CO emissions of 2.0 ppmvd @ 15% O_2. Depending on inlet CO concentrations, oxidation catalysts have demonstrated the ability to achieve CO reduction efficiencies of approximately 70-90%.

Catalytic oxidation is considered a technically feasible and commercially available CO control technology for the proposed Deer Creek NGCC. Based on information available from technology vendors, and emission rates achieved in practice at similar sources, it is concluded that a catalytic oxidation system could achieve a controlled CO emission rate of 3.3 ppmvd (or approximately 2.0 ppmvd @ 15% O_2). Based on emission rates of 9.0 ppmvd (without duct firing) and 18.3 ppmvd (with duct firing) the oxidation catalyst system would have to achieve CO removal efficiencies in the range of 63-82%.

4.2.2.2 Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)

The EMx™ control system is described in the NOx BACT analysis (section 3.2.2.3). EMx™ is a post-combustion, multi-pollutant control technology that uses a coated oxidation catalyst to remove NOx, CO, and VOC emissions in the turbine exhaust gas by oxidizing CO to CO_2, NO to NO_2, and hydrocarbons to CO_2 and water. The CO_2 is then emitted to the atmosphere, and the NO_2 is absorbed onto the potassium carbonate coating

Best Available Control Technology

on the EMx™ catalyst to form potassium nitrate/nitrite. Depending on flue gas temperatures, the EMx™ oxidation catalyst should achieve CO removal efficiencies similar to those achievable with an oxidation catalyst.

As discussed in section 3.2.2.2, there are several currently unresolved technical issues associated with application of the control technology on a large natural gas-fired combined cycle unit. Potential issues include:

- For large-scale NGCC applications, the EMx™ catalyst would have to be placed in the HRSG where the exhaust gas temperatures will be in the range of 500 to 700 °F. Performance of the EMx™ catalyst in a high-temperature application has not been demonstrated in practice.
- The dampers and damper bearings, which are moving parts exposed to the hot exhaust gas, could present long-term maintenance and reliability problems. This is particularly true as the damper size and number of dampers increase, as would be necessary in order to use this technology for Deer Creek.
- Regeneration of the EMx™ catalyst would require hydrogen gas to be continuously generated (from natural gas) and introduced into the high-temperature zone of the HRSG. Because hydrogen gas is explosive, any leaks in the dampers used to isolate the catalyst for regeneration could create a serious hazard.
- In addition to periodic regeneration, the EMx™ catalyst would have to be cleaned at least once per year by removing the catalyst beds from the HRSG and dipping them in a potassium carbonate solution.
- The EMx™ and ESx™ processes have the potential to create additional air pollutants, such as hydrogen sulfide (H_2S). Emissions of these additional pollutants have not been completely quantified.

To date, the EMx™ (SCONOx) multi-pollutant control system has not been installed and operated on a large NGCC application. It is likely that BEPC would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system at the Deer Creek Station. BACT does not require applicants to experience extended time delays or resource penalties to allow research to be conducted on an emerging control technique. Therefore, at this time the EMx™ control system is not considered an available CO control system, and will not be further evaluated in the BACT analysis.

Best Available Control Technology

4.2.2.3 Catalytic Combustion (Xonon™)

Catalytic combustion systems are described in the NOx BACT analysis (section 3.2.2.6). Catalytic combustion uses a catalyst within the combustor to oxidize a lean air-to-fuel mixture rather than burning with a flame. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NOx, and potentially lower CO emissions. One technical challenge associated with catalytic combustion has been achieving catalyst life long enough to make the combustor commercially viable. The Xonon™ combustion system works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is lower temperature partial combustion followed by flameless catalytic combustion to reduce CO formation.

As described in section 2.3.3.6, to date, the system has successfully completed pilot- and full-scale testing, and has been demonstrated on a 1.5 MW Kawasaki gas turbine. However, the Xonon™ combustion system has not been demonstrated for extended periods of time on a large natural gas-fired combustion turbine. Applications of this technology have been in the 1 to 15 MW range. It is likely that BEPC would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system at the Deer Creek Station. BACT does not require applicants to experience extended time delays or resource penalties to allow research to be conducted on an emerging control technique. Therefore, at this time, catalytic combustion systems (including Xonon™) are not considered available CO control systems, and will not be further evaluated in the BACT analysis.

The results of Step 2 of the CO BACT Analysis (technical feasibility analysis of potential CO control technologies) are summarized in Table 4-2.

Best Available Control Technology

Table 4-2
Technical Feasibility of Potential CO Control Technologies

Control Technology	Controlled CO Emission* ppmvd	In Service on Existing NGCC Units: Yes	In Service on Existing NGCC Units: No	Technically Feasible on the Deer Creek NGCC Unit?
Combustion Controls	9.0 (unfired) 18.3 (fired)	X		Yes
Oxidation Catalyst	3.3 (unfired) 3.3 (fired)	X		Yes. Note, a controlled CO emission rate of 3.3 ppmvd is equivalent to an emission rate of approximately 2.0 ppmvd @ 15% O_2.
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)	NA	X (limited application)		This control technology has not been demonstrated on a large natural gas-fired NGCC, and, at this time, is not considered technically feasible or commercially available for the Deer Creek NGCC unit.
Catalytic Combustion (Xonon™)	NA	X (limited application)		This control technology has not been demonstrated on a large natural gas-fired NGCC, and, at this time, is not considered technically feasible or commercially available for the Deer Creek NGCC unit.

*Emission rates included in this table represent enforceable permit limits that should be achievable under all normal operating conditions based on a 30-day rolling average period.

4.3 Step 3: Rank the Technically Feasible CO Control Options by Effectiveness

The technically feasible and commercially available CO control technologies are listed in Table 4-3 in descending order of control efficiency.

Best Available Control Technology

Table 4-3
Technical Feasibility of Potential CO/VOC Control Technologies

Technology	Controlled CO Emission Rate (ppmvd)*
Combustion Controls	9.0 (unfired) 18.3 (fired)
Oxidation Catalyst	3.3 (unfired)

* Emission rates shown in this table represent controlled emission rates that should be achievable based on a 30-day rolling average.

4.4 Step 4: Evaluate the Technically Feasible CO Control Technologies

4.4.1 CO Control Technologies – Economic Evaluation

The most effective CO control system, in terms of reduced emissions, that is considered to be technically feasible for the proposed NGCC unit consists of combustion controls and post-combustion oxidation catalyst. This combination of controls should be capable of achieving the most stringent controlled CO emission rates on an on-going long-term basis.

The effectiveness of the oxidation catalyst system is dependent on several site-specific system variables including inlet CO concentrations, the size of the oxidation catalyst system (i.e., number of catalyst layers), flue gas temperatures, and catalyst deactivation rate. The size of the oxidation catalyst will be limited by pressure drop across the catalyst bed and by the location of the proposed SCR control system. Based on emission rates achieved in practice at similar sources, and including a reasonable margin to account for normal system fluctuations and long-term system operation, the combination of combustion controls and oxidation catalyst should achieve controlled CO emission rates of 3.3 ppmvd (30-day rolling average).

The second most effective CO control system is combustion controls designed to minimize CO formation while maintaining NOx at acceptable levels. Based on information available from burner vendors, the dry-low NOx burners proposed for the Deer Creek NGCC should be able to maintain an average CO concentration of 9.0 ppmvd (7.4 ppmvd @ 15% O_2), while limiting average NOx emissions to 15 ppmvd @ 15% O_2. CO emissions associated with duct firing will be limited to 0.05 lb/mmBtu (heat input to the duct burner). Based on emission calculations at full load heat input to the boiler and maximum duct firing, duct firing will increase CO emissions in the exhaust from 9.0 to 18.3 ppmvd.

Economic impacts associated with the potentially feasible CO control systems were evaluated in accordance with EPA guidelines in the NSR Review Manual. For the economic impact analysis, projected annual emissions (tpy) were used to evaluate average cost effectiveness (i.e., dollar per ton removed). Annual emissions (tpy) were calculated assuming: (1) full load heat input to the combustion turbine with maximum heat input to the duct burners for 2,200 hours per year; (2) full load heat input to the combustion turbine without duct firing for 5,852 hours/year; and (3) startup/shutdown emissions for the remaining 708 hours of the year. Detailed emission calculations for each operating scenario are included in Appendix B to the Deer Creek PSD Permit Application.

Cost estimates were compiled from a number of data sources. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual.[6] Major equipment costs were developed based on published information available from equipment vendors, equipment costs recently developed for similar projects, and cost estimates included in other recently submitted PSD permit applications. Capital costs include the equipment, material, labor, and all other direct costs needed to install the control technologies.

Fixed and variable O&M costs were developed for each control system. Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumable, including reagent (if applicable), by-product management, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with operation of the control technology, including operation of larger fans to overcome pressure drop across the control system.

Summarized in Table 4-4 are the expected controlled CO emission rates and annual CO mass emissions associated with each technically feasible control technology. Table 4-5 presents the capital costs and annual operating costs associated with building and operating each control system. Table 4-6 shows the average annual cost effectiveness and incremental annual cost effectiveness for each control system. A detailed summary of the cost estimates used in this BACT analysis is included in Attachment B to this BACT Analysis.

[6] U.S. Environmental Protection Agency, *EPA Air Pollution Cost Control Manual*, 6th Ed., Publication Number EPA 452/B-02-001, January 2002.

Best Available Control Technology

The average annual cost effectiveness of the oxidation catalyst control system is calculated to be $3,324/ton (CO). Equipment costs, energy costs, and annual operating costs (e.g., routine catalyst replacement) all have a significant impact on the cost of the oxidation catalyst control system.

Based on economic impacts, oxidation catalyst control for CO should be eliminated from consideration as BACT. Capital costs of the oxidation catalyst system (estimated at $1,133,000), as well as O&M costs (including auxiliary power and catalyst replacement costs) are both significant. Power costs, associated with additional fan power required to overcome pressure drops across the oxidation catalyst, are estimated to be $173,000/year. Catalyst replacement costs are estimated to be $137,000/year. Total annual costs associated with the oxidation catalyst system, including capital recovery are estimated to be in the range of $479,300/year. The significant increase in total annual costs coupled with the relatively small decrease in annual emissions (estimated at 144.2 tpy) results in a relatively high average cost effectiveness for the oxidation catalyst control system.

Although oxidation catalyst control systems have been required for CO and VOC control on natural gas-fired combined cycle units, several recently issued PSD permits have been issues with combustion controls as BACT for CO (see, Attachment A to this BACT Analysis). Recently issued PSD permits listed in the RBLC Database requiring good combustion as BACT for CO include Arsenal Hill Power Plant (LA, 3/20/2008), Fairbault Energy Park (MN, 6/5/2007), Progress Bartow Power Plant (FL, 1/26/2007), and Northern States Power Co., Riverside Plant (MN, 5/16/2006).

Best Available Control Technology

Table 4-4
Annual CO Emissions

Combustion Controls	CO Emission Rate ppmvd	CO Emissions (lb/hr)	Hours per Year (hr)	Total Annual Emissions (tpy)
Full Load Heat Input w/o Duct Firing	9.0	28.5	5,852	83.4
Full Load Heat Input with Duct Firing	18.3	57.2	2,200	62.9
Startup / Shutdown Emissions	--	--	708	108.0
Total Annual Emissions	--	--	--	254.3

Oxidation Catalyst	CO Emission Rate ppmvd	CO Emissions (lb/hr)	Hours per Year (hr)	Total Annual Emissions (tpy)
Full Load Heat Input w/o Duct Firing	3.3	7.6	5,852	22.2
Full Load Heat Input with Duct Firing	3.3	10.3	2,200	11.3
Startup / Shutdown Emissions	--	--	708	76.6
Total Annual Emissions	--	--	--	110.1

Table 4-5
CO Emission Control System
Cost Summary

Control Technology	Total Capital Investment* ($)	Total Capital Investment ($/kW-gross)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
Oxidation Catalyst System	$1,133,000	$4.54	$107,000	$372,300	$479,300

* Capital costs include the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the control system.

Table 4-6
CO Emission Control System
Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Cost Effectiveness ($/ton)
Oxidation Catalyst System	$479,300	144.2	$3,324

Best Available Control Technology

The RBLC Database includes limited information regarding cost effectiveness analyses conducted for NGCC CO controls. However, JEA recently submitted a PSD permit application to the Florida Department of Environmental Quality (FLDEQ) for it Greenland Energy Center (GEC). The permit application, dated 9/10/2008, was for two GE 7FA combined cycle units.[7] The BACT analysis for the JEA-GEC facility estimated the cost effectiveness of CO control with an oxidation catalyst at $2,161/ton. JEA concluded that an oxidation catalyst was not BACT for CO control based on "…the economic impacts detailed in the application, as well as recent Department determinations for similar units at similar emission levels."[8] JEA cited several other combined cycle BACT determinations that did not require oxidation catalyst for CO control, including FPL Turkey Point, TECO Bayside Power Station, FMPA Treasure Coast, Progress Energy Hines Power Block 4, and FMPA Cane Island Unit 2.

Another recent example is MyPower Corp's PSD permit application for its proposed Lakeside Energy Center near Waco, Texas (submitted to the Texas Commission on Environmental Quality in December 2008. The proposed Lakeside facility includes two new natural gas-fired combined cycle units. The BACT analysis for the Lakeside Energy Center estimated the cost effectiveness of CO control with an oxidation catalyst at $1,990/ton, and conclude that "[t]his value is considered to be higher than what is considered BACT for CO emissions."[9] The most recent NGCC unit listed in the RBLC Database that identified oxidation catalyst as BACT for CO control and included a cost effectiveness value is the Plant McDonough Combined Cycle facility in Georgia (GA, 1/7/2008). That permit included a CO with an emission limit of 1.8 ppm @ 15% O_2 at a cost effectiveness of $1,750/ton.

Based on a review of the RBLC Database and recently submitted PSD permit applications, oxidation catalyst emission control has been required in or near ozone non-attainment areas for VOC control, and for CO control on units with a cost effectiveness less than approximately $2,000/ton. Oxidation catalyst control systems have not generally been required for CO control on units located in attainment areas. Based on the economic impact

[7] A copy of the JEA-GEC permit application and BACT analysis is available at: http://www.dep.state.fl.us/Air/ permitting/construction.htm.

[8] JEA-GCE BACT Analysis, page 3-29.

[9] MyPower Corp., Lakeside Energy Center PSD Permit Application, page 6-6, available from TCEQ.

associated with post-combustion CO control, BEPC is eliminating oxidation catalyst from consideration as BACT.

4.4.2 CO Control Technologies – Environmental Impacts

Combustion modifications designed to decrease CO formation also tend to increase the formation and emission of NOx. Combustion controls, including dry low-NOx burners, need to be designed to reduce the formation of NOx while maintaining CO at acceptable levels. Other than the NOx/CO trade-off, there are no environmental issues associated with using combustion controls to reduce CO emissions from a natural gas-fired combustion turbine.

Operation of an oxidation catalyst control system has certain collateral environmental consequences. The most significant environmental impact is associated with increased condensible PM10 emissions. The oxidation catalyst also tends to oxidize flue gas SO_2 to SO_3. Based on information available from catalyst vendors, the SO_2 to SO_3 oxidation rate varies with flue gas temperatures, but will be in the range of 50% for high temperature CO catalyst. SO_3 can react with water to form sulfuric acid mist, or with ammonia slip from the SCR to form ammonium sulfate and/or ammonium bisulfate. Sulfuric acid mist and ammonium sulfate are classified as condensable particulates; thus, oxidation catalyst control can result in increased PM10 emissions.

Based on emission calculations (assuming 50% SO_2 to SO_3 oxidation across the oxidation catalyst, 5 ppm ammonia slip, and 100% conversion of ammonia to ammonium sulfate) an oxidation catalyst system located upstream of the SCR will increase condensible PM10 emissions (when not duct firing) by approximately 2.5 lb/hr (or potentially 11 tpy). Total PM10 emissions (including periods of duct firing) will increase from approximately 80 tpy to approximately 91 tpy. Although actual emission increases will likely be less (assuming ammonia slip less than 5 ppm), the potential increase in condensible PM10 emissions is significant and supports the conclusion that an oxidation catalyst control system should be excluded as BACT for CO control.

4.4.3 CO Control Technologies – Energy Impacts

Post-combustion CO control with an oxidation catalyst control system requires auxiliary power. Auxiliary power requirements associated with an oxidation catalyst includes additional fan power to overcome pressure drop through system. Based on engineering calculations, pressure drop through the oxidation catalyst will be in the range of approximately 1.5 in. w.c. Assuming 220 kW/inch auxiliary power requirement, and a power cost of $60/MWh, auxiliary power costs for the oxidation catalyst control system will be in the range of $173,000/year. This cost was included in the economic impact evaluation of the oxidation catalyst system (section 4.4.1), and contributes to the relatively high cost effectiveness value of the system for the control of CO emissions.

A summary of the Step 4 economic, environmental, and energy impact analysis is provided in Table 4-7.

Table 4-7
Summary of CO BACT Impact Analysis

Control Technology	**Controlled CO Emission Rate* ppmvd**	**Annual CO Emissions (tpy)***	**Economic Impacts: Average Cost Effectiveness ($/ton removed)**	**Environmental Impacts**
Combustion Controls	9.0 (w/o duct firing) 18.3 (w/ duct firing)	254.3	--	Combustion controls designed to reduce CO emissions could result in an increase in NOx emissions.
Oxidation Catalyst	3.3	110.1	$3,324	Potential collateral environmental impacts include increased SO_2 to SO_3 oxidation and increased condensible particulate emissions. The oxidation catalyst system will also require auxiliary power to overcome pressure drop through the system.

* Annual emissions were calculated based on a full load combustion turbine operation at annual average ambient conditions without duct firing for approximately 5,852 hours per year, full load operation with duct firing for 2,200 hours per year, and estimated startup/shutdown emissions. Detailed emission calculations are included in Appendix B of the Deer Creek PSD Permit Application.

4.5 Step 5: Select BACT for CO Control

Based on the foregoing control technology evaluation, BACT evaluations included in recently submitted PSD permit applications for similar sources, and BACT limits included in recently issued PSD permits (Attachment A), it is concluded that combustion controls represent BACT for CO control for the proposed Deer Creek NGCC unit. Post-combustion oxidation catalyst control

Best Available Control Technology

is being rejected as BACT based on the significant economic impact associated with the installation and operation of the control system, the limited cost effectiveness of the control system, and the collateral environmental and energy impacts.

Based on emission rates achieved in practice at similar sources, and including a reasonable margin to account for normal system fluctuations and long-term operation, combustion controls should achieve a controlled CO emission rate of 9.0 ppmvd (30-day average) without duct firing and 18.3 ppmvd when duct firing. These controlled emission rates should be achievable under all normal combustion turbine operating scenarios (excluding startup and shutdown), while maintaining NOx emissions within acceptable limits. Achieving these emission limits will require the facility to properly operate, tune, and maintain the combustion turbine and duct burners on a continuous on-going basis.

Best Available Control Technology

5.0 BACT ANALYSIS FOR COMBUSTION TURBINE PM CONTROL

Because natural gas is an inherently clean fuel, filterable PM emissions are typically low.[10] Filterable emissions are generally considered to be the particles that are captured by the filter in the front-half of a Method 5 or Method 17 sampling train. Condensible particulate matter is material that is emitted in the vapor state which later condenses to from aerosol particulates. Particulate matter from natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted, and may result from poor air/fuel mixing or maintenance problems.

Total PM (including filterable and condensible fractions) from natural gas combustion are generally assumed to be less than 1.0 micrometer in size.[11] For this BACT evaluation it has been assumed that all PM emitted from the CT/HRSG will be less than 2.5 micrometer in size; therefore, PM, PM10, and PM2.5 emission rates are equal. All PM emissions, including PM10 and PM2.5 will be referred to as “PM”.

5.1 Step 1: Identify Potentially Feasible PM Control Options

Potentially available PM control options were identified based on a review of available information including PM emission controls identified in recently issued PSD permits for NGCC units listed in U.S.EPA’s RBLC Database (Attachment A). PM control options with potential application to the proposed Deer Creek NGCC unit include mechanical collectors, wet scrubbing systems, electrostatic precipitators (ESP), and fabric filter baghouses.

5.2 Step 2: Technical Feasibility of Potential PM Control Options

Natural gas is an inherently clean fuel, and particulate emissions associated with firing natural gas will be minimal. Several particulate control systems have been designed for use on boilers firing fuels that generate significant levels of uncontrolled PM, including boilers firing coal and residual oils. The principal techniques for particulate control from these types of units include mechanical collectors, scrubbing systems, electrostatic precipitators, and fabric filter baghouses. All of these systems have been used extensively on high-particulate boilers; however, these control devices have not been used in natural gas-fired applications, as uncontrolled PM emissions associated with natural gas firing are typically below the controlled emission rates achieved with particulate

[10] See, AP-42 page 1.4-3.

[11] See, AP-42, Table 1.4-2, footnote c.

control systems. Due to the inherently low PM emissions associated with firing natural gas, post-combustion particulate matter control systems would have no practical application to the proposed NGCC unit.

The New Source Review Manual states that "[t]echnical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration."[12] This determination of applicability should be made based on an examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. In this case, the potential PM emissions from the NGCC unit will be significantly lower then controlled PM emission rates achieved with post-combustion control systems on units firing high-particulate fuels. Based on a comparison of flue gas characteristics and engineering judgment, it is concluded that post-combustion particulate control systems have no practical application to a combined cycle unit exclusively firing natural gas.

5.3 Step 3: Rank the Technically Feasible PM Control Options by Effectiveness

The technically feasible control technologies with a practical application to control PM emissions from a natural gas-fired combined cycle unit are listed in Table 5-1 in descending order of control efficiency.

Table 5-1
Summary of Technically Feasible and Applicable
NGCC PM Control Technologies

Control Technology	Total PM Emission Rate (lb/hr)
Natural Gas Firing and Combustion Controls	18.6 (without duct firing) 23.2 (with duct firing)

* PM emissions were calculated based on emissions information available from combustion turbine and duct firing burner vendors. Detailed emission calculations are included in Appendix B to the Deer Creek PSD Permit Application.

[12] U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990 ("NSR Manual"), page B.18.

Best Available Control Technology

5.4 Step 4: Evaluate the Technically Feasible PM Control Technologies

5.4.1 PM Control Technologies – Economic Evaluation

There are no technically feasible and commercially available PM control technologies applicable to a natural gas-fired combined cycle unit. The inherently low particulate content of natural gas-fuel coupled with good combustion practices is the only applicable PM control strategy available. Because BEPC is proposing the only control strategy that has a practical application to the proposed NGCC unit, no cost effectiveness analysis is required.

5.4.2 PM Control Technologies – Environmental Impacts

There are no significant collateral environmental issues associated with firing natural gas and using combustion controls that would exclude the technology from consideration as BACT for PM control.

5.5 Step 5: Select BACT for PM Control

BEPC is proposing natural gas-firing and combustion controls as BACT for PM. Based on emissions information available from combustion turbine and duct burner vendors, BEPC is proposing a total PM (filterable + condensible) BACT emission rate of 18.6 lb/hr (approximately 0.01 lb/mmBtu) at full load without duct firing, and 23.2 lb/hr (approximately 0.01 lb/mmBtu) at full load with duct firing. These emission rates includes both filterable and condensible PM, and includes condensibles generated from operation of the SCR control system. All recently permitted NGCC units have been permitted with combustion controls as BACT for PM (see, Attachment A). Because BEPC is proposing to use the only technically feasible control strategy with a practical application to the proposed emission unit, natural gas and combustion controls should be considered BACT for PM control.

6.0 BACT ANALYSIS FOR THE EMERGENCY GENERATOR, FIRE WATER PUMP, AND EMERGENCY INLET AIR HEATER

6.1 Emergency Generator and Fire Water Pump BACT Analysis

In addition to the combustion turbine and heat recovery steam generator, the Deer Creek Station will have an emergency diesel generator (EDG) and emergency fire-water pump (FWP). The EDG will supply power to the essential service motor control centers during an interruption of the electrical power supply to the site, including building heat and fuel supply systems, plant communication systems, and essential emergency lighting. The FWP provides power the fire-water pumps in the event of an emergency. Based on preliminary design calculations, the EDG will be designed to provide 2,000 kW power during emergency situations, and the FWP will be designed at 577 hp to provide water at a rate of 3,000 gpm.

The diesel engines will be designed to fire low-sulfur diesel fuel. Both engines will be used only in case of an emergency and for periodic testing. Annual hours of operation are expected to be less than 100 hour/year each, however, for emissions estimating purposes it was assumed that both engines would operate a maximum of 150 hours per year. Limiting the hours of operation to 150 hours/year will reduce potential annual emissions from the diesel-fired engines by approximately 98%.

6.1.1 Diesel Engine - Baseline Emission Rates

Diesel engines are classified as compression ignition (CI) internal combustion (IC) engines. In diesel-fueled CI engines, diesel fuel is injected into the combustion air after the combustion air is compression heated in the engine's cylinder. Ignition of the fuel/air mixture is spontaneous because the combustion air temperature is above the autoignition temperature of the mixture. The resulting high-pressure products of combustion push the piston through the cylinder. Movement of the piston is converted from linear to rotary motion by a crankshaft.

The primary pollutants from IC engines are NOx, hydrocarbons (HC), CO, and PM. NOx formation is directly related to high pressures and temperatures during the combustion process and to the fuel nitrogen content. The other pollutants, HC, CO, and PM are primarily the result of incomplete combustion. IC engines also have the potential to emit SO_2 emissions. Potential SO_2 emissions are directly related to the sulfur content of the fuel.

Table 6-1 summarizes typical emission levels from diesel-fired CI-IC engines based on data published by the U.S.EPA and the Manufactures of Emission Controls Association (MECA).

Table 6-1
Diesel-Fired Compression Ignition Engines
Emission Factors

Source	NOx	CO	PM	NMHC (Note 1)
AP-42 Section 3.4 Large Stationary Diesel Engines (Table 3.4-1)	10.9 g/hp-hr (uncontrolled) 5.9 g/hp-hr (controlled-Note 2)	2.5 g/hp-hr	0.32 g/hp-hr	0.31 g/hphr
AP-42 Section 3.3 Diesel Industrial Engines <600 hp (Table 3.3-1)	14.1 g/hp-hr	3.03 g/hp-hr	1.0 g/hp-hr	1.12 g/hp-hr
MECA (Note 3)	11.6 g/hp-hr	1.0 g/hp-hr	0.25 – 0.8 g/hp-hr	0.3 g/hp-hr

Note 1: NMHC refers to nonmethane hydrocarbon emissions.
Note 2: Controlled NOx is by ignition timing retard.
Note 3: Emission factors published by the Manufacturers of Emission Controls Association.[13]

6.1.2 Diesel Engine - Potentially Feasible Emission Control Technologies

Emission control technology development for CI engines has primarily been directed at limiting NOx and CO emissions since they are the primary pollutants from these engines. The most common control techniques for diesel CI engines focus on modifying the combustion process to minimize NOx formation and products of incomplete combustion, including CO and HC. More recently, post-combustion absorption systems and catalytic reduction systems have become available for non-road and stationary diesel-fired CI engines. A summary of the potentially feasible combustion controls and post-combustion controls is provided below.

6.1.2.1 Combustion Controls

From an emissions control perspective, the most important distinction between different IC engines is whether they are rich-burn or lean-burn.[14] Rich-burn engines have an air-

[13] See, "Emission Control Technology for Stationary Internal Combustion Engines," Manufacturers of Emission Control Association, Status Report, July 1997.

[14] See, AP-42 Section 3.3, page 3.3-3.

to-fuel ratio operating range that is near stoichiometric or fuel-rich of stoichiometric and as a result the exhaust gas has little or no excess oxygen. Lean-burn engines have an air-to-fuel operating range that is fuel-lean of stoichiometric; thus, exhaust from these engines is characterized by medium to high levels of O_2. Diesel engines are inherently lean-burn engines.

Combustion modifications developed to minimize emissions from CI engines include injection timing retard (ITR), air-to-fuel ratio, and derating.[15] As described above, the injection of diesel fuel into the cylinder of a CI engine initiates the combustion process. Retarding the timing of the diesel fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NOx formation.

The air-to-fuel ratio can be adjusted by controlling the amount of fuel that enters each cylinder. CI engines are inherently lean-burn engines; however, by reducing the air-to-fuel ratio to near stoichiometric, combustion will occur under conditions of less excess oxygen and reduced combustion temperatures. Lower oxygen levels and combustion temperatures will reduce NOx formation. Derating involves restricting engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures thereby lowering NOx formation rates.

Combustion controls continue to develop for large stationary and non-road diesel engines. Combustion controls have demonstrated the ability to reduce NOx emissions from CI engines by approximately 50%. Based on AP-42 emission factors (Table 3.4-1), ITR can reduce NO_x emissions from large stationary diesel-fired engines from approximately 10.9 g/hp-hr to approximately 5.9 g/hp-hr.

6.1.2.2 Post-Combustion Emission Control Technologies

Post-combustion absorption systems and catalytic reduction systems are becoming available for diesel-fired stationary CI engines. A list of potentially feasible post-combustion control technologies applicable to large stationary diesel-fired CI engines is included in Table 6-2. A description of each potentially feasible technology is provided

[15] See, AP-42 Section 3.4, page 3.4-3.

below.[16]

Table 6-2
Potentially Feasible Post-Combustion CI Emission Control Technologies

Control Technology	Target Pollutants
NOx Absorbers	NOx
NSCR Catalyst	NOx, CO, NMHC
Lean-NOx Catalyst	NOx
Oxidation Catalyst	CO, NMHC
SCR Catalyst	NOx
Diesel Particulate Filter	PM
Catalytic Diesel Particulate Filter	PM, CO, NMHC

6.1.2.2.1 NOx Absorption Systems

Post-combustion NOx absorption systems have been developed to remove NOx from CI engine exhaust. In a NOx absorption system, NOx is absorbed on a storage catalyst, from which it is periodically reduced during a regeneration process. The process of trapping NOx can be either catalytic absorption or adsorption. NOx reduction and catalyst regeneration is typically accomplished by injecting additional fuel just before the catalyst, creating conditions that enable the NOx molecules to be reduced with a precious metal catalyst that doesn't work under lean conditions (i.e., excess oxygen). One concern with NOx absorption systems is the life of the catalyst. To date, NOx absorption catalysts have been very sensitive to poisoning by sulfur. Oxides of sulfur take sites on the catalyst and cannot be removed without impractical high temperatures. Low-sulfur fuels will reduce this problem, and sulfur traps are being developed in conjunction with NOx absorber catalysts that are more sulfur tolerant.

[16] The following documents were relied upon for emission control technology descriptions included in this report: (1) "Emission Control Technology for Stationary Internal Combustion Engines," Manufacturers of Emission Control Association, Status Report, July 1997; (2) "Diesel Particulate Filters", Washington State University Extension Energy Program; and (3) Huang, Y., Dang, Z., et al, "Development and Applications of Catalyzed Diesel Particulate Filter", Presented at the 10th DEER Meeting, August 2004.

6.1.2.2.2 Catalytic Reduction Systems

Catalytic reduction systems are also being developed for CI engines. The principle behind catalysts for the control of gaseous emissions from stationary IC engines is that the catalyst creates reducing conditions at acceptable temperatures without being consumed. Catalytic emission control systems typically consist of a steel housing containing a metal or ceramic structure that acts as the catalyst substrate. Catalysts have been developed to reduce NOx, CO, and NMHC emissions to varying degrees.

Nonselective catalytic reduction systems (NSCR) have been developed to gaseous emissions from rich-burn engines. NSCR systems can reduce NOx, CO, and NMHC emissions in engines that are operated stoichiometrically or fuel-rich of stoichiometric. In the presence of CO and NMHC in the engine exhaust, NSCR catalysts convert NOx to nitrogen and oxygen, CO to O_2 and NMHC to CO_2 and water. However, NSCR catalytic reactions require that O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios. NOx conversion efficiencies drop dramatically in lean-burn engines. Lean-burn engines are characterized by an oxygen-rich exhaust, minimizing the potential for NOx reduction.

Research and development has been carried out in the area of lean-NOx catalysts. Lean-NOx catalysts are designed to reduce NO_x to nitrogen and water in an oxygen-rich environment. Although a relatively new technology, catalyst formulations and substructures have been developed that can reduce NOx emissions in the oxygen-rich diesel exhaust environment. However, durability of the substructures has proven to be a challenge. Development work continues with both base metal and precious metal catalysts. The injection of a small amount of reducing agent upstream of the catalyst may also improve lean-NOx catalyst performance and durability.

Oxidation catalysts have been used on off-road mobile source lean-burn engines. Oxidation catalyst systems contain precious metals impregnated onto a high geometric surface area substrate and are placed in the exhaust stream. Oxidation catalysts have proven effective in controlling CO and NMHC emissions from mobile source CI engines. Oxidation catalyst systems may also reduce particulate emissions from diesel engines by oxidizing the soluble organic fraction of the particulate. Concerns with oxidation catalyst systems include catalyst life, catalyst poisoning, and regeneration of catalyst that has sintered or become deactivated.

Selective catalytic reduction (SCR) systems are being developed to control NOx emissions from stationary CI engines. SCR control systems introduce a reducing agent such as ammonia or urea into the diesel exhaust over a catalyst. The catalyst reduces the temperature needed to initiate the reaction between the reducing agent and NOx to form nitrogen and water.

Both precious metal and base metal catalysts have been used in SCR systems. Base metal catalysts, typically vanadium and titanium, are used for exhaust gas temperatures between 450 ^{o}F and 800 ^{o}F. For higher temperatures (675 to 1100 ^{o}F), zeolite catalysts may be used. Concerns with SCR control systems include catalyst deactivation and poisoning. Sulfur compounds in the exhaust can poison SCR catalysts and reduce the catalyst activity.

With all catalyst control systems, including SCR, oxidation, or lean-NOx catalytic controls on an IC engine, conditions exist that can reduce catalyst activity. Catalytic deactivation may result from (1) chemical poisoning, (2) masking, or (3) thermal sintering. In most cases, the reduced performance results from catalysts being masked by contaminants in the exhaust. Contaminants in diesel-fired CI exhaust include oxides of sulfur and particulates. Catalyst that has been deactivated will not be as effective at reducing the target pollutants. Spent catalysts must be properly managed to prevent improper disposal.

6.1.2.2.3 Particulate Control Systems

Diesel particulate emissions are composed of a variety of liquid phase hydrocarbons, and solid phase soot (carbon). Diesel particulate filter (DPF) systems have been developed to control particulate matter emissions from stationary diesel engines. These devices generally consist of a wall-flow type filter positioned in the exhaust stream of the diesel engine. As exhaust gases pass through the system, particulates are removed and retained on the filter media. As the mass of collected particulate matter increases, exhaust gas flow through the filter may become impeded, resulting in an increased backpressure within the filter and reduced engine efficiency. When the backpressure reaches a certain level, the filter needs to be cleaned or regenerated for reuse.

Best Available Control Technology

Regeneration of filters has been accomplished by periodically enriching the air-to-fuel mixture. An enriched air-to-fuel mixture produces a higher exhaust gas temperature to burn off particulate matter contained in the filter. Thermal filter regeneration of diesel particulate filters typically requires temperatures above 600 ^{o}F, and may not be desirable because it can lead to uncontrolled ignition of soot and filter substrate damage. Catalytic regeneration systems have been developed to regenerate DPF collection systems at lower temperatures.

Both precious metal and base metal catalysts have been used to reduce the filter regeneration temperature in catalyzed diesel particulate filter (CDPF) control systems. Catalysts reduce the temperature needed to oxidize particulate matter collected in the filter, reducing the potential for temperature overshoot and filter substrate damage. CDPF catalysts are being developed with high activity for the oxidation of CO, HC, and soot, and low activity towards O_2 oxidation.

6.1.3 Diesel Engine - Controlled Emission Rates

On July 11, 2006, USEPA published final requirements to reduce emissions of air pollutants from stationary CI internal combustion engines (71 FR 39152). The final Stationary Compression Ignition Internal Combustion Engine (CI ICE) New Source Performance Standard (NSPS) limits emissions of NOx, PM, SO_2, CO, and HC from stationary diesel internal combustion engines.

As part of the rulemaking process, USEPA evaluated the technical feasibility, effectiveness, and cost effectiveness of potentially feasible control technologies, including the control technologies described above. The final CI ICE NSPS requirements were based on the best demonstrated system of continuous emission reduction, considering costs, non-air quality health, and environmental and energy impacts. Manufactures, owners, and operators of diesel engines will be required to meet the applicable NSPS emission standards. The CI ICE NSPS rule will take effect in three increasingly stringent stages:

1. The first stage is a transition period to control emissions from diesel engines built after the rule was proposed, but before the 2007 model year. Owners/operators will comply with this regulation by purchasing an appropriate engine and by operating and maintaining the engine according to the manufacturers' instructions.

2. Beginning in the model year 2007, engine manufacturers will be required to certify

that all new, modified, or reconstructed stationary diesel engines meet the emission levels for NO_x, PM, CO, and HC that are required for the same size engine and model year for nonroad diesel engines in the categories designated as Tiers 1 through 4, with a few exceptions.

3. Beginning with 2011 model year engines, add-on controls will be required to achieve the emission limits for non-emergency engines.

Provisions of the CI ICE NSPS apply to manufacturers, owners, and operators of stationary CI internal combustion engines. CI engines include internal combustion engines that are not spark ignition engines, including diesel engines. Both the EDG and FWP are classified as stationary CI engines, and are subject to the provisions of the CI ICE NSPS.

Emissions standards established in the rule depend on the engines horsepower class and mode of operation (e.g., continuous operation or emergency operation). Specific definitions applicable to the Deer Creek diesel engines include “emergency stationary internal combustion engine” and “fire pump engine”. Emergency stationary internal combustion engines include:

> any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc….

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection. The EDG and FWP are both classified as emergency stationary internal combustion engines, and the FWP meets the definition of a fire pump engine.

The NSPS includes emission standards for model year 2007 and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kW (3,000 hp) and a displacement of less than 10 liters per cylinder that are not fire pump engines (40 CFR 60.4202). The EDG engine proposed for the Deer Creek Station will fall into this classification of engines. The rule requires that emergency stationary CI ICE meet the Tier 2 through Tier 3 non-road CI engine emission standards, and Tier 4 non-road CI engine standards that do not require add-on control, according to the non-road diesel engine schedule in 40 CFR 89.112 and 40 CFR 89.113. CI ICE NSPS emission standards applicable to the EDG are summarized in Table 6-3.

Table 6-3
CI ICE NSPS Emission Standards Applicable to the Deer Creek Station Emergency Diesel Generator

kW > 560	NOx		HC		NMHC +NOx		CO		PM	
	g/kW-h	g/HP-h	g/kW-h	g/HP-h	g/kW-h	g/HP-h	g/kW-h	g/HP-h	g/kW-h	g/HP-h
Tier 1	9.2	6.86	1.3	0.97	--	--	11.4	8.50	0.54	0.40
Tier 2	--	--	--	--	6.4	4.77	3.5	2.61	0.20	0.15

Fire pump engines are subject to the final rule beginning with the first model year that new fire pump engines in a particular horsepower class must meet standards more stringent than Tier 1 standards, which can be any model year from 2008 to 2011, depending on the horsepower of the engine (40 CFR 60.4202(d)). CI ICE NSPS emission standards applicable to the FWP are summarized in Table 6-4.

Table 6-4
CI ICE NSPS Emission Standards Applicable to the Deer Creek Station Emergency Diesel Generator

175 > HP < 750	NMHC +NOx		CO		PM	
	g/kW-h	g/HP-h	g/kW-h	g/HP-h	g/kW-h	g/HP-h
2009+	4.0	3.0	3.5	2.6	0.20	0.15

NSPS emission standards for emergency stationary engines and fire pump engines are based on combustion controls, but will not necessarily require add-on post-combustion controls. Emergency engines require control technologies that have the highest reliability while in the standby mode and require minimal time and adjustments to bring on-line. Combustion controls represent the most reliable control strategy for engines that will not operate on a continuous basis.

Best Available Control Technology

6.1.4 Post-Combustion Emission Control Cost Effectiveness Evaluation

As part of the NSPS rulemaking process, USEPA evaluated the cost-effectiveness of potentially feasible post-combustion emission control systems. Cost-effectiveness calculations were prepared for various CI engines based on the engines' horsepower rating and mode of operation. Cost effectiveness evaluations were included in the technical information published by USEPA to support the CI ICE NSPS.[17]

Post-combustion control technologies evaluated by USEPA included NOx absorbers and catalyzed diesel particulate filters (CDPF), which were the technologies that were the basis for the proposed NSPS emission standards for the control of NOx and PM, respectively. Cost effectiveness evaluations for the applicable horsepower ratings and mode of operation (i.e., emergency operation) are summarized in Table 6-5.

Table 6-5
Cost of Control per Ton of Pollutant Removed with NOx Adsorbers and CDPF[18]

HP Range*	**Cost per ton NOx Removed**		**Cost per ton PM Removed**		**Cost per ton NOx + PM Removed**	
	($/ton)		**($/ton)**		**($/ton)**	
	Prime	Emergency	Prime	Emergency	Prime	Emergency
300 – 600	$816	$22,049	$12,866	$348,278	$767	$20,736
1,200 – 3,000	$498	$13,472	$35,857	$969,121	$492	$13,287

*The fire-water pump will fall into the 300 – 600 hp range, and the emergency generator will be within the 1,200 – 3,000 hp range.

USEPA also evaluated the cost-effectiveness of SCR control systems. The applicable SCR cost-effectiveness results are summarized in Table 6-6.

[17] Cost effectiveness evaluations summarized in this BACT analysis can be found in the CI ICE NSPS Docket, Docket ID No. OAR-2005-0029, http://www.epa.gov/ttn/atw/nsps/cinsps/cinspspg.html.

[18] See, Memorandum from Tanya Parise, Alpha-Gamma Technologies, Inc. to Sims Roy, EPA OAQPS ESD Combustion Group, Subject: Cost per Ton for NSPS for Stationary CI ICE, dated June 9, 2005. A copy of the memorandum is included in the CI ICE NSPS Docket.

Best Available Control Technology

Table 6-6
Cost of Control per Ton of NOx Removed with SCR

HP Range	Cost per ton NOx Removed ($/ton)	
	Prime	Emergency
300 - 600	$14,685	$396,886
1,200 – 3,000	$8,972	$242,493

Finally, USEPA evaluated the cost per ton of particulate removal using oxidation catalyst. As described above, oxidation catalyst systems reduce particulate emissions from diesel engines by oxidizing the soluble organic fraction of the particulate. The applicable oxidation catalyst cost-effectiveness results are summarized in Table 6-7.

Table 6-7
Cost of Control per Ton of PM Removed with Oxidation Catalyst

HP Range	Cost per ton PM Removed ($/ton)	
	Prime	Emergency
300 – 600	$6,048	$163,458
1,200 – 3,000	$13,148	$355,344

Based on economic impact evaluations prepared by USEPA to support the CI ICE NSPS, post-combustion controls are not currently cost effective for emergency stationary CI engines. This conclusion is reflected in the final CI ICE NSPS regulation, which requires emergency CI ICE units to meet the most stringent emission standards that do not require add-on control. Post-emission control systems are relatively expensive, require additional maintenance, and provide minimal annual emission reductions on units that are used on an infrequent basis. Furthermore, emergency engines require control technologies that have the highest reliability while in the standby mode and require minimal time and adjustments to bring on-line.

Best Available Control Technology

6.1.5 Proposed Emergency Diesel Generator and Fire Water Pump BACT

BEPC is proposing low sulfur diesel fuel, combustion controls, and limited annual hours of operation as BACT for the emergency diesel generator and fire water pump. BEPC will meet the applicable CI ICE NSPS emission standards. The applicable NSPS standards were based on the best demonstrated system of continuous emission reduction, considering costs, non-air quality health, and environmental and energy impacts, while taking into consideration that emergency engines require control technologies that have the highest reliability while in the standby mode and require minimal time and adjustments to bring on-line. Commercial availability of post-combustion control technologies is limited, and post-combustion control systems are not economically feasible on emergency stationary CI engines.

6.2 Emergency Inlet Air Heater BACT Analysis

The Deer Creek Station will have one natural gas-fired emergency inlet air heater. The function of the heater is to preheat the combustion turbine intake air during periods of extremely cold ambient conditions (i.e., ambient temperature less than approximately -25 °F). The air heater will warm a solution of water and ethylene glycol, which will be piped to a heat exchanger placed at the CT air intake to heat the inlet air. It is anticipated that the heater will operate for approximately 10 to 20 minutes during CT startup under extreme conditions. Once the CT is up to speed, the emergency inlet air heater will be shut off and bleed heat from the compressor will be used to heat the inlet air. The heater design will be based on a maximum heat input of 25.0 mmBtu/hr to provide a heat duty of 19.0 mmBtu/hr, and designed to fire pipeline natural gas.

Annual emissions from the emergency inlet air heater will be limited by limiting its hours of operation. The heater will only be used for short periods of time during extremely cold ambient conditions. For emissions estimating purposes it was assumed that during some years the inlet gas heater might need to operate as much as 150 hours. This assumption is considered conservative, because in most years the inlet air heater is expected to operate significantly less.

6.2.1 Emergency Inlet Air Heater – Potential Emissions

Potential emissions associated with the combustion of natural gas include NOx, CO, particulate matter, and SO_2. NOx formation generally results from the oxidation of atmospheric nitrogen contained in the inlet gas in the high-temperature post-flame region of the combustion zone. CO emissions are generally associated with incomplete combustion.

Particulate matter and SO_2 emissions associated with firing natural gas will be minimal. Particulate matter from natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted, and may result from poor air/fuel mixing or maintenance problems. SO_2 emissions are directly related to the sulfur content of the fuel. Natural gas has an inherently low sulfur content.

6.2.2 Emergency Inlet Air Heater – Potentially Feasible Emission Control Technologies

NOx and CO represent the primary emissions from the inlet air heater. Emissions of both pollutants can be controlled using combustion controls.

The principal mechanism of NOx formation in natural gas combustion is thermal NOx. Thermal NOx is formed when nitrogen and oxygen in the combustion air combine with one another at the high temperatures in a flame. Two significant factors influencing thermal NOx formation include flame temperature and the quantity of excess air. High excess air levels can result in increased NOx formation because the excess nitrogen and oxygen in the combustion air entering the flame will combine to form thermal NOx. Low excess air firing involves limiting the amount of excess air that is entering the combustion process. NOx formation is inhibited because less oxygen is available in the combustion zone. Limiting the amount of excess air entering a flame is accomplished through burner design.

Low NOx burners (LNB)[19] limit NOx formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen in the primary combustion zone, reduced flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NOx emissions during the combustion process.

However, combustion controls designed to reduce NOx formation can adversely affect CO emissions. Combustion controls used to reduce thermal NOx (e.g., cooler flame and reduced

[19] The term "LNB" is used generically in this BACT analysis, and refers to advanced low-NOx burners available from leading boiler/burner manufacturers..

O_2 availability) tend to increase the formation and emission of CO. During combustion, carbon in the fuel oxidizes to form carbon dioxide (CO_2). CO emissions are formed when carbon in the fuel is only partially oxidized. CO formation is minimized when the boiler temperature and excess oxygen availability are adequate for complete combustion. Proper burner design and operation can minimize CO emissions while maintaining NOx emissions at acceptable levels.

Other potentially available control options were identified based on a review of available information, including emission controls required in recently issued PSD permits for natural gas-fired boilers listed in USEPA's RBLC Database. A summary of NOx and CO emissions and emission control technologies identified in the RBLC Database for small process boilers and heaters firing natural gas (Process Type 13.310) is provided in Attachment A.

All of the recently permitted natural gas-fired process heaters included in the RBLC Database were permitted with combustion controls as BACT for NOx and CO. Although post-combustion control technologies, such as selective catalytic reduction and catalytic oxidation systems, may be technically feasible to further reduce NOx and CO emissions, post-control systems have not been permitted or installed on small natural gas-fired process heaters. Based on a review of recently permitted natural gas-fired heaters, post-combustion control systems have not been required to control emissions fromf natural gas-fired heaters, and post-combustion control systems have not been demonstrated in practice on these units. Therefore, post-combustion emission control systems will not be evaluated for the emergency inlet air heater.

6.2.3 Emergency Inlet Air Heater - Controlled Emission Rates

As discussed above, all of the recently permitted natural gas-fired process heaters included in the RBLC Database were permitted with combustion controls as BACT. Combustion controls will minimize the formation and emission of NOx, while maintaining CO emissions at acceptable levels. Furthermore, natural gas is an inherently clean fuel, with minimal particulate and SO_2 emissions.

NOx emissions listed in the RBLC Database for natural gas-fired heaters similar in size to the proposed inlet air heater (i.e., in the range of approximately 15 to 35 mmBtu/hr heat input) have been permitted with NOx emission rates in the range of 0.045 to approximately 0.13 lb/mmBtu (see Attachment A). All of the units were permitted with combustion controls as

Best Available Control Technology

BACT for NOx. These controlled emission rates are similar to the AP-42 emission factor for small natural gas-fired boilers equipped with low NOx burners (50 lb/mmscf or 0.049 lb/mmBtu, AP-42 Table 1.4-1).

CO emissions listed in the RBLC Database for natural gas-fired heaters similar in size to the proposed inlet air heater (i.e., in the range of approximately 15 to 35 mmBtu/hr heat input) have been permitted with CO emission rates in the range of 0.08 to approximately 0.10 lb/mmBtu (see Attachment A). All of the units were permitted with combustion controls as BACT for CO. These controlled emission rates are similar to the AP-42 emission factor for small natural gas-fired boilers equipped with low NOx burners (84 lb/mmscf or 0.08 lb/mmBtu, AP-42 Table 1.4-1).

6.2.4 Proposed Emergency Inlet Air Heater BACT

BEPC is proposing low sulfur diesel fuel, combustion controls, and limited annual hours of operation as BACT for the emergency inlet air heater. Based on a review of available information, including emission limits included in recently issued PSD permits for similar sources, BEPC is proposing the following NOx and CO BACT limits:

- NOx 50 lb/mmscf (approximately 0.048 lb/mmBtu)
- CO 84 lb/mmscf (approximately 0.08 lb/mmBtu)

7.0 DEER CREEK STATION - BACT ANALYSIS SUMMARY

Tables 7-1 and 7-2 provide a summary of the proposed BACT emission limits, and associated control technologies, for the Deer Creek Station. Emission rates, control efficiencies, and control technologies proposed for the Deer Creek Station are consistent with the emission rates and technologies proposed for similar facilities. In addition, air quality dispersion modeling based on the proposed emission rates demonstrates that impacts from the proposed facility will be below applicable state and federal standards.

Table 7-1
Proposed CT/HRSG BACT Emission Limits and Control Technologies

Pollutant	Proposed BACT Emission Limits	Proposed BACT Technology	Compliance Demonstration Methodology
NOx	3.5 ppmvd @ 15% O_2 (30-day rolling average)	Selective Catalytic Reduction (SCR)	NOx CEMs
CO	9.0 ppmvd (without duct firing) 18.3 ppmvd (with duct firing) (30-day rolling averages)	Combustion Controls	CO CEMs
Total PM (filterable + condensible)	18.6 lb/hr (without duct firing) 23.2 lb/hr (with duct firing) (avg. of 3 1-hour test runs)	Combustion Controls	Stack Test, U.S.EPA Test Methods 201a/202 or the equivalent with Department approval.

Table 7-2
Proposed Auxiliary Combustion Sources BACT Emission Limits and Control Technologies

Source	Proposed BACT Emission Limits	Proposed BACT Technology	Compliance Demonstration Methodology
Emergency Diesel Generators	Compliance with the applicable CI ICE NSPS	Combustion controls, low-sulfur diesel fuel and limited hours of operation	Compliance with the applicable CI ICE NSPS
Fire Water Pump	Compliance with the applicable CI ICE NSPS	Combustion controls, low-sulfur diesel fuel and limited hours of operation	Compliance with the applicable CI ICE NSPS
Emergency Inlet Air Heater	NOx: 0.048 lb/mmBtu CO: 0.08 lb/mmBtu	Combustion controls and limited hours of operation	Operation in accordance with manufacturer's specifications

Best Available Control Technology

Attachment A

RACT/BACT/LAER Clearinghouse Database Search

The following tables provide a summary of facilities listed in the RACT/BACT/LAER Clearinghouse (RBLC) Database. A search of the RBLC Database was conducted in May 2009. The following tables were prepared and included as part of this Attachment:

Table A-1	Natural Gas Combined Cycle NOx Emissions
Table A-2	Natural Gas Combined Cycle CO Emissions
Table A-3	Natural Gas Combined Cycle PM Emissions
Table A-4	Small Natural Gas-Fired Process Heater NOx Emission
Table A-5	Small Natural Gas-Fired Process Heater CO Emissions

Best Available Control Technology

Table A-1
Recent Natural Gas Combined Cycle NOx BACT Determinations (2004 – 2008)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	EMISSION LIMIT AVERAGING TIME/CONDITIONS
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	15.11	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTUREâ€™S RECOMMENDED PROCEDURES.	400	LB/H	MAX
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	15.21	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTUREâ€™S RECOMMENDED PROCEDURES.	400	LB/H	MAX
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	15.11	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTUREâ€™S RECOMMENDED PROCEDURES.	400	LB/H	MAX
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	15.21	2110	MMBTU/H	LOW NOX TURBINES, DUCT BURNERS COMBINED WITH SCR	30.15	LB/H	MAX
CT-0151	KLEEN ENERGY SYSTEMS, LLC	CT	2/25/2008	15.21	2.1	MMCF/H	LOW NOX BURNER AND SELECTIVE CATALYTIC REDUCTION	15.5	LB/H	W/OUT DUCT BURNER
*MN-0071	FAIRBAULT ENERGY PARK	MN	6/5/2007	15.21	1758	MMBTU/H	DRY LOW NOX COMBUSTION FOR NG; WATER INJECTION FOR NO.2 OIL; SCR W/NHZ INJECTION IN HRSG FOR BOTH NG & NO. 2 OIL.	3	PPMVD	3-HR. AVG CTG & DB NAT. GAS OR DB NO OPE
CA-1144	BLYTHE ENERGY PROJECT II	CA	4/25/2007	15.21	170	MW	SELECTIVE CATALYTIC REDUCTION	2	PPMVD	AT 15% O2, 3-HR AVG
FL-0285	PROGRESS BARTOW POWER PLANT	FL	1/26/2007	15.21	1972	MMBTU/H	WATER INJECTION	15	PPMVD UNCORRECTED	30-DAYS BASIS - NATURAL GAS
FL-0285	PROGRESS BARTOW POWER PLANT	FL	1/26/2007	15.11	1972	MMBTU/H	WATER INJECTION DRY LOW NOX	15	PPMVD	4-HOURS BASIS - NATURAL GAS UNCORRECTED
*FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	15.21	2333	MMBTU/H	DRY LOW NOX AND SCR WATER INJECTION	2	PPMVD @15%O2	24-HR (GAS)
*FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	13.31	99.8	MMBTU/H		0.05	LB/MMBTU	
TX-0497	INEOS CHOCOLATE BAYOU FACILITY	TX	8/29/2006	15.21	35	MW	BP AMOCO PROPOSES TO USE SCR TO CONTROL NOX EMISSIONS FROM BOTH TURBINES AND DUCT BURNERS AFTER CONSIDERING ALTERNATIVE NOX CONTROL METHODS. THE TURBINES AND DUCT BURNERS WILL ALSO USE LOW NOX COMBUSTORS. BP AMOCO PROPOSES	11.43	LB/H	3-HR AVG.
FL-0280	TREASURE COAST ENERGY CENTER	FL	5/30/2006	15.2	170	MW	SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPMVD	24-HR BLOCK (GAS)
*NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	5/10/2006	15.21	2221	MMBUT/H	SCR	2	PPMVD@15%02	
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LLC	CO	5/2/2006	15.21	300	MW	LOW NOX BURNERS AND SCR	3	PPM @ 15% O2	HOURLY MAX
NJ-0066	AES RED OAK LLC	NJ	2/16/2006	15.2	63122	MMSCF/YR	SELECTIVE CATALYTIC REDUCTION(SCR) FOR EACH TURBINE.	25.3	LB/H	
NC-0101	FORSYTH ENERGY PLANT	NC	9/29/2005	15.21	1844.3	MMBTU/H	DRY LOW-NOX COMBUSTORS AND SELECTIVE CATALYTIC REDUCTION (SCR)	2.5	PPM @ 15% O2	24 HOUR ROLLING AVERAGE, FIRST 500 HOURS
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	NV	8/16/2005	15.21	306	MW	SELECTIVE CATALYST REDUCTION W/ AMMONIA INJECTION	2	PPM @ 15% O2	3-HOUR ROLLING

Best Available Control Technology

Table A-1: Recent Natural Gas Combined Cycle NOx BACT Determinations (2004 – 2008) continued:

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	EMISSION LIMIT AVERAGING TIME/CONDITIONS
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	NV	8/16/2005	15.21	306	MW	SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION	2	PPM @ 15% O2	3-HOUR ROLLING
*OR-0041	WANAPA ENERGY CENTER	OR	8/8/2005	15.21	2384.1	MMBTU/H	DRY LOW-NOX BURNERS AND SCR.	2	PPMDV @ 15% O2	3 HOURS
FL-0265	HINES POWER BLOCK 4	FL	6/8/2005	15.21	530	MW	SCR	2.5	PPM	NATURAL GAS
MI-0366	BERRIEN ENERGY, LLC	MI	4/13/2005	15.21	1584	MMBTU/H	DRY LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION.	2.5	PPMDV @ 15% O2	24-HOUR ROLLING AVG EACH HOUR
FL-0263	FPL TURKEY POINT POWER PLANT	FL	2/8/2005	15.21	170	MW	NOX EMISSIONS WILL BE REDUCED WITH DRY LOW-NOX (DLN) COMBUSTION TECHNOLOGY FOR GAS FIRING AND WATER INJECTION FOR OIL FIRING. IN COMBINATION WITH THESE NOX CONTROLS, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM FURTHER REDUC	2	PPMVD@ 15 % O2	24-HR (ALL MODES OF OPERATION)
*WA-0328	BP CHERRY POINT COGENERATION PROJECT	WA	1/11/2005	15.21	174	MW	LEAN PRE-MIX DRY LOW-NOX BURNERS ON CT. LOW NOX DUCT BURNERS. SCR.	2.5	PPMDV	3-HR @ 15%O2
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FAC	OH	12/28/2004	15.21	172	MW	DRY LOW NOX (DLN) BURNERS AND SELECTIVE CATALYTIC REDUCTION(SCR)	21.1	LB/H	EACH TURBINE
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FAC	OH	12/28/2004	15.21	172	MW	DRY LOW NOX (DLN) BURNERS AND SELECTIVE CATALYTIC REDUCTION (SCR)	27.8	LB/H	EACH TURBINE
CA-1142	PASTORIA ENERGY FACILITY	CA	12/23/2004	15.21	168	MW	XONON CATALYTIC COMBUSTORS OR DRY LOW NOX BURNERS WITH SCR	2.5	PPMVD	@ 15% O2, 1-HR AVG
AZ-0047	WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	15.21	170	MW	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION	2	PPM AT 15% O2	THREE-HOUR
AZ-0047	WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	15.21	180	MW	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION	2	PPM @ 15% O2	3-HOUR AVERAGE
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	MS	11/23/2004	15.21	230	MW	SCR	3.5	PPMV @ 15% 02	3-HOUR AVG.
NV-0033	EL DORADO ENERGY, LLC	NV	8/19/2004	15.21	475	MW	LOW NOX BURNER + SCR	3.5	PPM @ 15% O2	For each turbine
CA-1143	SUTTER POWER PLANT	CA	8/16/2004	15.21	170	MW	DRY LOW NOX BURNERS & SCR	2.5	PPMVD	AT 15% O2, 1-HR AVG
VA-0291	CPV WARREN LLC	VA	7/30/2004	15.21	1717	mmbtu/h	TWO STAGE LEAN PERMIX DRY LOW NOX COMBUSTION SCR AND GOOD COMBUSTION PRACTICES.	2	PPM	AS A ONE HOUR AVERAGE
MN-0053	FAIRBAULT ENERGY PARK	MN	7/15/2004	15.21	1876	MMBTU/H	SCR AND DLN.	3	PPMVD @ 15% 02	3 HOUR AVERAGE
MN-0053	FAIRBAULT ENERGY PARK	MN	7/15/2004	15.11	1663	MMBTU/H	DRY LOW-NOX COMBUSTORS OPERATING IN LEAN PREMIX MODE.	25	PPMVD @ 15% 02	3 HOUR AVERAGE
UT-0066	CURRANT CREEK	UT	5/17/2004	15.21			CONVENTIONAL SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION	2.25	PPMVD	3-HOUR/COMBINED CYCLE(17 LB/H)
NV-0037	COPPER MOUNTAIN POWER	NV	5/14/2004	15.21	600	MW	DRY LOW-NOX COMBUSTOR, STEAM INJECTION, AND SELECTIVE CATALYTIC REDUCTION	2	PPMVD	15% OXYGEN, 3-HR AVERAGE
VA-0289	DUKE ENERGY WYTHE, LLC	VA	2/5/2004	15.21	170	MW	SCR AND LOW NOX BURNERS; GOOD COMBUSTION PRACTICES	2.5	PPMVD	
VA-0289	DUKE ENERGY WYTHE, LLC	VA	2/5/2004	15.21	170	MW	SCR AND LOW NOX BURNERS. GOOD COMBUSTION PRACTICES.	2.5	PPMVD	EACH UNIT

Best Available Control Technology

Table A-2
Recent Natural Gas Combined Cycle CO BACT Determinations (2004 – 2008)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROC TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISS UNIT 1	EMISS LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME / CONDITIONS
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	15.11	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTUREâ€™S RECOMMENDED PROCEDURES.	1,508.15	LB/H	MAX
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	15.21	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTUREâ€™S RECOMMENDED PROCEDURES.	1,575.80	LB/H	MAX
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	15.11	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTUREâ€™S RECOMMENDED PROCEDURES.	964.57	LB/H	MAX
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	15.21	2110	MMBTU/H	PROPER OPERATING PRACTICES	143.31	LB/H	MAX
CT-0151	KLEEN ENERGY SYSTEMS, LLC	CT	2/25/2008	15.21	2.1	MMCF/H	CO CATLYST	4.30	LB/H	W/OUT DUCT BURNER
*GA-0127	PLANT MCDONOUGH COMBINED CYCLE	GA	1/7/2008	15.21	254	MW	OXIDATION CATALYST	1.80	PPM @ 15% O2	3-HOUR
*GA-0127	PLANT MCDONOUGH COMBINED CYCLE	GA	1/7/2008	15.29	254	MW	OXIDATION CATALYST	9.00	PPM@15% O2	3-HOUR, FIRING FUEL OIL
*MN-0071	FAIRBAULT ENERGY PARK	MN	6/5/2007	15.21	1758	MMBTU/H	GOOD COMBUSTION	9.00	PPMVD	3-HR. AVG CTG ON NG NO DB
CA-1144	BLYTHE ENERGY PROJECT II	CA	4/25/2007	15.21	170	MW		4.00	PPMVD	AT 15% O2, 3-HR AVG
FL-0285	PROGRESS BARTOW POWER PLANT	FL	1/26/2007	15.21	1972	MMBTU/H	GOOD COMBUSTION	8.00	PPMVD	24-HR BLOCK AVERAGE CEMS
FL-0285	PROGRESS BARTOW POWER PLANT	FL	1/26/2007	19.9	3	MMBTU/H		0.08	LB/MMBTU	
FL-0285	PROGRESS BARTOW POWER PLANT	FL	1/26/2007	15.11	1972	MMBTU/H	GOOD COMBUSTION	8.00	PPMVD	@ 15% O2 - OIL
*FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	15.21	2333	MMBTU/H		8.00	PPMVD @15%O2	24-HR
*FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	13.31	99.8	MMBTU/H		0.08	LB/MMBTU	

Best Available Control Technology

Table A-2: Recent Natural Gas Combined Cycle CO BACT Determinations (2004 – 2008) continued:

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROC TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISS UNIT 1	EMISS LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME / CONDITIONS
TX-0497	INEOS CHOCOLATE BAYOU FACILITY	TX	8/29/2006	15.21	35	MW	BP AMOCO PROPOSES PROPER COMBUSTION CONTROL AS BACT FOR CO AND VOC EMISSIONS FROM THE TURBINES AND DUCT BURNERS. CO EMISSIONS FROM EACH TURBINE WILL NOT EXCEED 15 PPMVD AT 85% TO 100% OF BASE LOAD. CO EMISSIONS FROM EACH TU	66.81	LB/H	
FL-0280	TREASURE COAST ENERGY CENTER	FL	5/30/2006	15.2	170	MW	GOOD COMBUSTION	6.00	PPM	12-MONTH ROLLING
MN-0066	NORTHERN STATES POWER CO. DBA XCEL ENERGY - RIVERSIDE PLANT	MN	5/16/2006	15.21	1885	mmbtu/h	GOOD COMBUSTION PRACTICES	10.00	PPMVD @ 15% O2	3-HR BLOCK
*NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	5/10/2006	15.21	2221	MMBUT/H	OXIDATION CATALYST	2.00	PPMVD@15%02	
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LLC	CO	5/2/2006	15.21	300	MW	USE GOOD COMBUSTION CONTROL PRACTICES AND CATALISTIC OXIDATION.	3.00	PPM @ 15% O2	
NJ-0066	AES RED OAK LLC	NJ	2/16/2006	15.2	63122	MMSCF/YR	OXIDATION CATALYST FOR EACH TURBINE.	20.69	LB/H	
NC-0101	FORSYTH ENERGY PLANT	NC	9/29/2005	15.21	1844.3	MMBTU/H	GOOD COMBUSTION PRACTICES AND EFFICIENT PROCESS DESIGN	25.90	PPM @ 15% O2	3-hr avg
NC-0101	FORSYTH ENERGY PLANT	NC	9/29/2005	15.21	1844.3	MMBTU/H	GOOD COMBUSTION PRACTICES AND EFFICIENT PROCESS DESIGN.	11.60	PPM @ 15% O2	3-hour average
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	NV	8/16/2005	15.21	306	MW	OXIDATION CATALYST	3.50	PPM @ 15% O2	3-HOUR ROLLING
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	NV	8/16/2005	15.21	306	MW	OXIDATION CATALYST SYSTEM	3.50	PPM @ 15% O2	3-HOUR ROLLING
MN-0060	HIGH BRIDGE GENERATING PLANT	MN	8/12/2005	15.21	330	MEGAWATTS	GOOD COMBUSTION PRACTICES	10.00	PPM @ 15% O2	TURBINE W/O DUCT-BURNER
*OR-0041	WANAPA ENERGY CENTER	OR	8/8/2005	15.21	2384.1	MMBTU/H	OXIDATION CATALYST.	2.00	PPMDV @ 15% O2	3 HOURS
FL-0265	HINES POWER BLOCK 4	FL	6/8/2005	15.21	530	MW	GOOD COMBUSTION	8.00	PPM	NATURAL GAS
MI-0366	BERRIEN ENERGY, LLC	MI	4/13/2005	15.21	1584	MMBTU/H	CATALYTIC OXIDATION.	2.00	PPMDV @ 15% O2	3-HOUR BLOCK

Best Available Control Technology

Table A-2: Recent Natural Gas Combined Cycle CO BACT Determinations (2004 – 2008) continued:

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROC TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISS UNIT 1	EMISS LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME / CONDITIONS
FL-0263	FPL TURKEY POINT POWER PLANT	FL	2/8/2005	15.21	170	MW	CO WILL BE MINIMIZED BY THE EFFICIENT COMBUSTION OF NATURAL GAS AND DISTILLATE OIL AT HIGH TEMPERATURES	8.00	PPMVD @ 15 % O2	24-HR AVG. TIME (CT & DUCT BURNER)
*WA-0328	BP CHERRY POINT COGENERATION PROJECT	WA	1/11/2005	15.21	174	MW	LEAN PRE-MIX CT BURNER & OXIDATION CATALYST	2.00	PPMDV	3-HR @ 15%O2
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	OH	12/28/2004	15.21	172	MW		25.70	LB/H	EACH TURBINE
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	OH	12/28/2004	15.21	172	MW		50.30	LB/H	EACH TURBINE
CA-1142	PASTORIA ENERGY FACILITY	CA	12/23/2004	15.21	168	MW	XONON CATALYTIC COMBUSTORS OR DRY LOW NOX BURNERS & SCR	6.00	PPMVD	@ 15% O2, 3-HR ROLLING AVG
AZ-0047	WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	15.21	170	MW	OXIDATION CATALYST	3.00	PPM @ 15% O2	3-HOUR AVERAGE
AZ-0047	WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	15.21	180	MW	OXIDATION CATALYST	3.00	PPM @ 15% O2	3-HOUR AVERAGE
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	MS	11/23/2004	15.21	230	MW	SCR	18.36	PPMV @ 1`5% 02	3-HOUR AVG.
MD-0032	DICKERSON	MD	11/5/2004	15.11	196	MW	OXIDATION CATALYST	84.20	LB/H	3HR AVG FIRING NG W/O DB IN SIMP CYCLE
MD-0032	DICKERSON	MD	11/5/2004	15.21	196	MW	OXIDATION CATALYST	8.40	LB/H	3HR AVG FIRING NG W/O DB IN COMB. CYCLE
MD-0032	DICKERSON	MD	11/5/2004	15.21	196	MW	OXIDATION CATALYST	7.60	LB/H	3-HR AVG FIRING NG W/DB IN COMB CYCLE
NV-0033	EL DORADO ENERGY, LLC	NV	8/19/2004	15.21	475	MW	OXIDATION CATALYST	2.60	PPM @ 15% O2	For each CTG
CA-1143	SUTTER POWER PLANT	CA	8/16/2004	15.21	170	MW	OXIDATION CATALYST SYSEM	4.00	PPMVD	AT 15% O2, 3-HR AVG
VA-0291	CPV WARREN LLC	VA	7/30/2004	15.21	1717	mmbtu/h	OXIDATION CATALYST. GOOD COMBUSTION PRACTICES.	1.30	PPMVD	W/O POWER AUGMENTATION

Best Available Control Technology

Table A-2: Recent Natural Gas Combined Cycle CO BACT Determinations (2004 – 2008) continued:

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROC TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISS UNIT 1	EMISS LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME / CONDITIONS
VA-0291	CPV WARREN LLC	VA	7/30/2004	15.21	1717	mmbtu/h	OXIDATION CATALYST, AND GOOD COMBUSTION PRACTICES.	1.80	PPMVD	POWER AUGMENTATION DUCT BURNING
MN-0053	FAIRBAULT ENERGY PARK	MN	7/15/2004	15.21	1876	MMBTU/H	GOOD COMBUSTION PRACTICES.	10.00	PPMVD @ 15% O2	3 HOUR AVERAGE
MN-0053	FAIRBAULT ENERGY PARK	MN	7/15/2004	15.11	1663	MMBTU/H	GOOD COMBUSTION PRACTICES.	10.00	PPMVD @ 15% 02	3 HOUR AVERAGE
UT-0066	CURRANT CREEK	UT	5/17/2004	15.21			OXIDATINO CATALYST FOR COMBINED CYCLE MODE OF OPERATION	3.00	PPMVD	3-HOUR/COMBINED CYCLE(11.6 LB/H)
NV-0037	COPPER MOUNTAIN POWER	NV	5/14/2004	15.21	600	MW	GOOD COMBUSTOR DESIGN AND AN OXIDATION CATALYST	3.00	PPMVD	15% OXYGEN, THREE-HOUR AVERAGE
VA-0289	DUKE ENERGY WYTHE, LLC	VA	2/5/2004	15.21	170	MW	GOOD COMBUSTION PRACTICES	14.60	PPMVD	
VA-0289	DUKE ENERGY WYTHE, LLC	VA	2/5/2004	15.21	170	MW	GOOD COMBUSTION PRACTICES.	9.00	PPMVD	

Best Available Control Technology

Table A-2
Recent Natural Gas Combined Cycle PM BACT Determinations (2004 – 2008)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROC TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISISON LIMIT	EMISSION LIMIT UNIT	EMISSION LIMIT AVERAGEING TIME/CONDITIONS
OR-0035	PORT WESTWARD PLANT	OR	1/16/2002	15.21	325	MW, EACH	USE OF PIPELINE QUALITY NATURAL GAS	0.1	GR/DSCF	EACH, STATE ENFORCED
ID-0010	MIDDLETON FACILITY	ID	10/19/2001	19.6	390	MMBTU/H	REASONABLE POLLUTION PREVENTION PRECAUTIONS.	0.03	LB/MMBTU	
TX-0351	WEATHERFORD ELECTRIC GENERATION FACILITY	TX	3/11/2002	15.11	1910	MMBTU/H	NONE INDICATED	18	LB/H	EACH UNIT
TX-0351	WEATHERFORD ELECTRIC GENERATION FACILITY	TX	3/11/2002	15.21	1079	MMBTU/H	NONE INDICATED	14	LB/H	EACH UNIT
FL-0263	FPL TURKEY POINT POWER PLANT	FL	2/8/2005	15.21	170	MW	PM/PM10 WILL BE MINIMIZED BY THE EFFICIENT COMBUSTION OF NATURAL GAS AND DISTILLATE OIL AT HIGH TEMPERATURES.			SEE NOTE
IN-0095	ALLEGHENY ENERGY SUPPLY CO. LLC	IN	12/7/2001	15.21	2071	MMBTU/H (HHV)	GOOD COMBUSTION PRACTICES	0.012	LB/MMBTU	
MS-0065	LONE OAK ENERGY CENTER, LLC	MS	11/13/2001	15.21	1837	MMBTU/H	GOOD COMBUSTION PRACTICES	24.9	LB/H	
MS-0065	LONE OAK ENERGY CENTER, LLC	MS	11/13/2001	15.21	1837	MMBTU/H	GOOD COMBUSTION PRACTICES	24.9	LB/H	
MS-0065	LONE OAK ENERGY CENTER, LLC	MS	11/13/2001	15.21	1837	MMBTU/H	GOOD COMBUSTION PRACTICES	24.9	LB/H	
MS-0051	LSP- BATESVILLE GENERATION FACILITY	MS	11/13/2001	15.21	2100	MMBTU/H	USE OF NATURAL GAS AS FUEL	40	LB/H	
*OR-0041	WANAPA ENERGY CENTER	OR	8/8/2005	15.21	2384.1	MMBTU/H				SEE POLUTANT NOTE
OK-0096	REDBUD POWER PLANT	OK	6/3/2003	15.21	1832	MMBTU/H	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	0.012	LB/MMBTU	
MN-0054	MANKATO ENERGY CENTER	MN	12/4/2003	15.21	1827	MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION	0.057	LB/MMBTU	3-HOUR AVG.
MN-0054	MANKATO ENERGY CENTER	MN	12/4/2003	15.21	1916	MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION PRACTICES	0.009	LB/MMBTU	3-HOUR AVERAGE
FL-0256	HINES ENERGY COMPLEX, POWER BLOCK 3	FL	9/8/2003	15.21	1830	MMBTU/H	PERMIT LIMIT IS CLEAN BURNING FUELS AND GOOD COMBUSTION PRACTICES. NO EMISSION LIMITS.			see note
NJ-0043	LIBERTY GENERATING STATION	NJ	3/28/2002	11.31	256	MMBTU/H	NONE LISTED	0.03	LB/MMBTU	
MN-0054	MANKATO ENERGY CENTER	MN	12/4/2003	11.31	800	MMBTU/H	CLEAN FUEL AND GOOD COMBUSTION	0.009	LB/MMBTU	3-HOUR AVG.
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002	11.31	385	MMBTU/H		0.03	LB/MMBTU	
OR-0039	COB ENERGY FACILITY, LLC	OR	12/30/2003	11.31	654	MMBTU/H	CLEAN FUEL	0.03	LB/MMBTU	
CA-1096	VERNON CITY LIGHT & POWER	CA	5/27/2003	15.21	43	MW GAS TURBINE, 55 MW STEAM TURBINE		0.01	G/SCF	
CA-1051	THREE MOUNTAIN POWER, LLC	CA	10/10/2003	15.2	2	MMBTU/H PLUS 290 MMBTU/H TO HRSG DUCT BURNERS		0.0012	G/DSCF @ 3% CO2	1 H

Best Available Control Technology

Table A-3: Recent Natural Gas Combined Cycle PM BACT Determinations (2004 – 2008) continued:

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROC TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISISON LIMIT	EMISSION LIMIT UNIT	EMISSION LIMIT AVERAGEING TIME/CONDITIONS
CA-1097	MAGNOLIA POWER PROJECT, SCPPA	CA	5/27/2003	15.21	181	NET MW (GAS TURBINE W/STEAM INJECTION)		0.01	G/SCF	
MS-0059	PIKE GENERATION FACILITY	MS	9/24/2002	15.21	2168	MMBTU/H	LOW ASH FUEL AND GOOD COMBUSTION PRACTICES	44.2	LB/H	
MS-0059	PIKE GENERATION FACILITY	MS	9/24/2002	15.21	2168	MMBTU/H	LOW ASH FUEL AND GOOD COMBUSTION PRACTICES	44.2	LB/H	
MS-0059	PIKE GENERATION FACILITY	MS	9/24/2002	15.21	2168	MMBTU/H	LOW ASH FUEL AND GOOD COMBUSTION PRACTICES	44.2	LB/H	
MS-0059	PIKE GENERATION FACILITY	MS	9/24/2002	15.21	2168	MMBTU/H	LOW ASH FUEL AND GOOD COMBUSTION PRACTICES	44.2	LB/H	
IA-0062	EMERY GENERATING STATION	IA	12/20/2002	15.2	170	MW	LOW ASH FUEL, NG	0.0072	LB/MMBTU	natural gas
FL-0247	TECO BAYSIDE POWER STATION	FL	1/8/2002	15.21	170	MW	FUEL SPECIFICATIONS, GAS ONLY.			see note
NE-0017	BEATRICE POWER STATION	NE	5/29/2003	15.21	80	MW		10.8	LB/H	
GA-0102	WANSLEY COMBINED CYCLE ENERGY FACILITY	GA	1/15/2002	15.21	167	MW	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0.011	LB/MMBTU	LHV BASIS
GA-0101	MURRAY ENERGY FACILITY	GA	10/23/2002	15.21	173	MW	GOOD COMBUSTION PRACTICE, CLEAN FUEL	25	LB/H	
VA-0260	HENRY COUNTY POWER	VA	11/21/2002	15.21	171	MW	GOOD COMBUSTION DESIGN AND CLEAN FUEL	25.3	LB/H	each unit
VA-0260	HENRY COUNTY POWER	VA	11/21/2002	15.21	171	MW	GOOD COMBUSTION AND DESIGN. CLEAN BURNING FUEL.	0.014	LB/MMBTU	@ 70%
VA-0287	JAMES CITY ENERGY PARK	VA	12/1/2003	15.21	1973	MMBTU/H	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	18	LB/H	each
MN-0053	FAIRBAULT ENERGY PARK	MN	7/15/2004	15.21	1876	MMBTU/H	CLEAN FUEL AND GOOD COMBUSTION PRACTICES.	0.01	LB/MMBTU	3 HOUR AVERAGE

Best Available Control Technology

Table A-4
Natural Gas-Fired Process Heater (<100 mmBtu/hr) RBLC NOx Permit Limit Summary (2004 to present)

RBLC ID	FACILITY NAME	STATE	PROCESS NAME	PROCESS TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	EMISSION LIMIT AVERAGING TIME
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	NATCO TEG REBOILER	13.31	1.34	MMBTU/H	CONVENTIONAL BURNER TECHNOLOGY	0.08	LB/MMBTU	
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	NATCO PRODUCTION HEATER	13.31	34	MMBTU/H	LOW NOX BURNERS / FLUE GAS RECIRCULATION	0.095	LB/MMBTU	
CO-0058	CHEYENNE STATION	CO	HEATERS	13.31	45	MMBTU/H	LOW NOX BURNERS	0.035	LB/MMBTU	1-HR AVERAGE
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	GA	FUEL GAS HEATER	13.31	5	MMBTU/H		99	PPM @ 15% O2	
GA-0107	TALBOT ENERGY FACILITY	GA	FUEL GAS PREHEATERS, (3)	13.31	5	MMBTU/H	DRY LOW NOX BURNERS	30	PPM @ 15% O2	
GA-0130	KIA MOTORS MANUFACTURING GEORGIA	GA	BOILERS AND HEATERS	13.31			LOW NOX BURNERS ON BOILER BURNERS	30	PPM @ 3%O2	BOILERS
IA-0062	EMERY GENERATING STATION	IA	GAS HEATER, (2)	13.31	16.4	MMBTU/H	DLN	0.049	LB/MMBTU	
IA-0063	WISDOM GENERATION STATION	IA	HEATER , NATURAL GAS	13.31	5.38	MMBTU/H	DLN	0.095	LB/MMBTU	
IA-0064	ROQUETTE AMERICA	IA	DEW POINT HEATER	13.31	1.6	MMBTU/H	GOOD COMBUSTION PRACTICES	0.15	LB/MMBTU	
IA-0068	EMERY GENERATING STATION	IA	GAS HEATER	13.31	9	MMBTU/H	DLN	0.049	LB/MMBTU	
IN-0116	PSEG LAWRENCEBURG ENERGY CO., INC.	IN	HEATER, STARTUP GAS, NATURAL GAS	13.31	2.4	MMBTU/H		0.14	LB/MMBTU	
LA-0192	CRESCENT CITY POWER	LA	FUEL GAS HEATERS (3)	13.31	19	MMBTU/H	LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	1.81	LB/H	HOURLY MAXIMUM
LA-0203	OAKDALE OSB PLANT	LA	AUXILIARY THERMAL OIL HEATER	13.31	66.5	MMBTU/H	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	7.82	LB/H	HOURLY MAXIMUM
MD-0035	DOMINION	MD	VAPORIZATION HEATER	13.31			ULNB	0.012	LB/MMBTU	
MD-0035	DOMINION	MD	EMERGENCY VENT HEATER	13.31			LNB	0.036	LB/MMBTU	3-HOUR AVERAGE
MD-0036	DOMINION	MD	FUEL GAS PROCESS HEATER	13.31			DRY LNB AND GOOD COMBUSTION PRACTICES	17	PPMVD	3-HOUR AVERAGE
MD-0036	DOMINION	MD	FUEL GAS PROCESS HEATER	13.31			GOOD COMBUSTION PRACTICES AND DRY LNB	17	PPMVD	3-HOUR AVERAGE
MD-0040	CPV ST CHARLES	MD	HEATER	13.31	1.7	MMBTU/H		0.1	LB/MMBTU	
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	SMALL BOILERS & HEATERS(<100 MMBTU/H)	13.31	99	MMBTU/H		0.0035	LB/MMBTU	3 HOUR AVERAGE
NE-0043	NATUREWORKS, LLC	NE	HOT OIL HEATER	13.31	75	MMBTU/H	LOW-NOX BURNERS & FGR			SEE NOTE
NJ-0062	CONSOLIDATE EDISON DEVELOPMENT (CED)	NJ	FUEL GAS HEATERS (3 UNITS)	13.31	4.62	MMBTU/H	LOW NOX -COMBUSTOR	0.17	LB/H	
NV-0047	NELLIS AIR FORCE BASE	NV	BOILERS/HEATERS - NATURAL GAS-FIRED	13.31			LOW-NOX BURNER AND FLUE GAS RECIRCULATION	0.03	LB/MMBTU	
OH-0264	NORTON ENERGY STORAGE, LLC	OH	FUEL SUPPLY HEATERS (9)	13.31	11.45	MMBTU/H		1.076	LB/H	
OH-0264	NORTON ENERGY STORAGE, LLC	OH	RECUPERATOR PRE-HEATERS (9)	13.31	12.84	MMBTU/H		1.207	LB/H	

Best Available Control Technology

Table A-4: Natural Gas-Fired Process Heater (<100 mmBtu/hr) RBLC NOx Permit Limit Summary (2004 to present), continued

RBLC ID	FACILITY NAME	STATE	PROCESS NAME	PROCESS TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	EMISSION LIMIT AVERAGING TIME
OK-0097	QUAD GRAPHICS OKC FAC	OK	HEATERS/OXIDIZERS	13.31	16	MMBTU/H	MAINTENANCE/OPERATION PER MANUFACTURE'S SPECIFICATION, AND EXCLUSIVELY FIRING COMMERCIAL NATURAL GAS OR PROPANE.	2.48	LB/H	
OK-0097	QUAD GRAPHICS OKC FAC	OK	BOILERS, NATURAL GAS, STEAM GENERATORS	13.31	600	HP	LOW NOX BURNERS, CLEAN FUEL, AND FLUE GAS RECIRCULATION	0.035	LB/MMBTU	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	HEAT TRANSFER FLUID HEATER, H202	13.31	31	MMBTU/H	NONE INDICATED	3.08	LB/H	0.099 lb/mmBtu
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	HEAT TRANSFER FLUID HEATER, H2202	13.31	31	MMBTU/H	NONE INDICATED	3.08	LB/H	0.099 lb/mmBtu
TX-0364	SALT CREEK GAS PLANT	TX	GLYCOL REBOILER, EPN11	13.31	2.5	MMBTU/H	NONE INDICATED	0.29	LB/H	
TX-0364	SALT CREEK GAS PLANT	TX	HP TEG FIREBOX, EPN30	13.31	3	MMBTU/H	NONE INDICATED	0.29	LB/H	
TX-0364	SALT CREEK GAS PLANT	TX	HOT OIL HEATER, EPN6	13.31	12	MMBTU/H	NONE INDICATED	1.41	LB/H	
TX-0364	SALT CREEK GAS PLANT	TX	HOT OIL HEATER, EPN26	13.31	32.5	MMBTU/H	NONE INDICATED	1.95	LB/H	0.060 lb/mmBtu
TX-0388	SAND HILL ENERGY CENTER	TX	INLET AIR HEATERS (3)	13.31				0.53	LB/H	
TX-0392	LUCITE BEAUMONT	TX	NO.1 PRE-HEATER	13.31				5.6	LB/H	
TX-0392	LUCITE BEAUMONT	TX	NO. 2 PRE-HEATER	13.31				3.8	LB/H	
WA-0301	BP CHERRY POINT REFINERY	WA	PROCESS HEATER, IHT	13.31	13	MMBTU/H	ULTRA LOW NOX BURNERS	0.1	LB/MMBTU	7% O2, 24 hr ave
WI-0195	SENA NIAGARA MILL	WI	PROCESS HEATER, PAPER MACHINE P51	13.31	34.4	MMBTU/H	ANY NEW (REPLACEMENT) IR BURNERS WILL BE LOW NOX BURNERS, FIRING NATURAL GAS	0.044	LB/MMBTU	
WI-0223	LOUISIANA-PACIFIC HAYWARD	WI	THERMAL OIL HEATER, GTS ENERGY, S31, B31	13.31	32	MMBTU/H	USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE	4.24	LB/H	0.133 lb/mmBtu
WI-0223	LOUISIANA-PACIFIC HAYWARD	WI	THERMAL OIL HEATER, GTS ENERGY, S32, B32	13.31	32	MMBTU/H	USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE	3.2	LB/H	0.100 lb/mmBtu
WI-0227	PORT WASHINGTON GENERATING STATION	WI	GAS HEATER (P06, S06)	13.31	10	MMBTU/H	NATURAL GAS FUEL	0.1	LBS/MMBTU	
WI-0228	WPS - WESTON PLANT	WI	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	13.31	0.75	MMBTU/H	NATURAL GAS	0.073	LB/H	
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 1	13.31	21	MMBTU/H	LOW NOX BURNERS	0.05	LB/MMBTU	HOURLY
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 2	13.31	21	MMBTU/H	LOW NOX BURNERS	0.05	LB/MMBTU	HOURLY
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 3	13.31	21	MMBTU/H	LOW NOX BURNERS	0.05	LB/MMBTU	HOURLY
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 4	13.31	21	MMBTU/H	LOW NOX BURNERS	0.05	LB/MMBTU	HOURLY
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 5	13.31	21	MMBTU/H	LOW NOX BURNERS	0.05	LB/MMBTU	HOURLY
WY-0067	ECHO SPRINGS GAS PLANT	WY	HOT OIL HEATER S38	13.31	84	MMBTU/H	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION	0.03	LB/MMBTU	

Best Available Control Technology

Table A-5
Natural Gas-Fired Process Heater (<100 mmBtu/hr) RBLC CO Permit Limit Summary (2004 to present)

RBLC ID	FACILITY NAME	STATE	PROCESS NAME	PROCESS TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	EMISSION LIMIT AVERAGING TIME
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	NATCO TEG REBOILER	13.31	1.34	MMBTU/H	GOOD OPERATIONAL PRACTICES	0.15	LB/MMBTU	
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	NATCO MISCIBLE INJECTION HEATER	13.31	14.87	MMBTU/H	GOOD OPERATIONAL PRACTICES	0.12	LB/MMBTU	
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	NATCO PRODUCTION HEATER	13.31	34	MMBTU/H	GOOD OPERATIONAL PRACTICES	0.10	LB/MMBTU	
CO-0058	CHEYENNE STATION	CO	HEATERS	13.31	45	MMBTU/H	GOOD COMBUSTION PRACTICES	0.037	LB/MMBTU	1-HR AVERAGE
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	GA	FUEL GAS HEATER	13.31	5	MMBTU/H		37	PPM @ 15% O2	
GA-0107	TALBOT ENERGY FACILITY	GA	FUEL GAS PREHEATERS, (3)	13.31	5	MMBTU/H	GOOD COMBUSTION PRACTICE	0.022	LB/MMBTU	
IA-0062	EMERY GENERATING STATION	IA	GAS HEATER, (2)	13.31	16.4	MMBTU/H		0.082	LB/MMBTU	
IA-0068	EMERY GENERATING STATION	IA	GAS HEATER	13.31	9	MMBTU/H	GOOD COMBUSTION PRACTICES	0.082	LB/MMBTU	
LA-0192	CRESCENT CITY POWER	LA	FUEL GAS HEATERS (3)	13.31	19	MMBTU/H	GOOD COMBUSTION PRACTICES	1.52	LB/H	HOURLY AVERAGE
LA-0193	STYRENE MONOMER PLANT	LA	REGENERATION GAS HEATER HS-2102	13.31	14.4	MMBTU/H	GOOD COMBUSTION PRACTICES - GOOD EQUIPMENT DESIGN, USE OF GASEOUS FUELS FOR GOOD MIXING, AND PROPER COMBUSTION TECHNIQUES	1.2	LB/H	HOURLY MAXIMUM
LA-0193	STYRENE MONOMER PLANT	LA	PEB RECOVERY COLUMN HEATER HS-2105	13.31	25.2	MMBTU/H	GOOD COMBUSTION PRACTICES - GOOD EQUIPMENT DESIGN, USE OF GASEOUS FUELS FOR GOOD MIXING, AND PROPER COMBUSTION TECHNIQUES	2.1	LB/H	HOURLY MAXIMUM
LA-0203	OAKDALE OSB PLANT	LA	AUXILIARY THERMAL OIL HEATER	13.31	66.5	MMBTU/H	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	6.57	LB/H	HOURLY MAXIMUM
MD-0035	DOMINION	MD	VAPORIZATION HEATER	13.31			EACH VAPORIZATION HEATER SHALL ONLY USE NATURAL GAS FOR FUEL AND SHALL USE GOOD COMBUSTION OPERATING PRACTICES	0.03	LB/MMBTU	
MD-0036	DOMINION	MD	FUEL GAS PROCESS HEATER	13.31			GOOD COMBUSTION PRACTICES	143	PPMVD	
MD-0040	CPV ST CHARLES	MD	HEATER	13.31	1.7	MMBTU/H		0.08	LB/MMBTU	
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	SMALL BOILERS & HEATERS(<100 MMBTU/H)	13.31	99	MMBTU/H		0.08	LB/MMBTU	1 HOUR AVERAGE
NE-0026	NUCOR STEEL DIVISION	NE	NNII BILET POST-HEATER	13.31	6.8	MMBTU/H		0.0084	LB/MMBTU	
NE-0026	NUCOR STEEL DIVISION	NE	NNII REHEAT FURNACE	13.31	143	MMBTU/H		0.066	LB/MMBTU	
NE-0043	NATUREWORKS, LLC	NE	HOT OIL HEATER	13.31	75	MMBTU/H	GOOD COMBUSTION PRACTICES			SEE NOTE
NJ-0062	CONSOLIDATE EDISON DEVELOPMENT (CED)	NJ	FUEL GAS HEATERS (3 UNITS)	13.31	4.62	MMBTU/H	GOOD COMBUSTION PRACTICE	0.69	LB/H	
NV-0047	NELLIS AIR FORCE BASE	NV	BOILERS/HEATERS - NATURAL GAS-FIRED	13.31			FLUE GAS RECIRCULATION	0.037	LB/MMBTU	
OH-0264	NORTON ENERGY STORAGE, LLC	OH	FUEL SUPPLY HEATERS (9)	13.31	11.45	MMBTU/H		0.96	LB/H	
OH-0264	NORTON ENERGY STORAGE, LLC	OH	RECUPERATOR PRE-HEATERS (9)	13.31	12.84	MMBTU/H		0.514	LB/H	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	HEAT TRANSFER FLUID HEATER, H202	13.31	31	MMBTU/H	NONE INDICATED	2.59	LB/H	0.084 lb/mmBtu
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	HEAT TRANSFER FLUID HEATER, H2202	13.31	31	MMBTU/H	NONE INDICATED	2.59	LB/H	0.084 lb/mmBtu
TX-0364	SALT CREEK GAS PLANT	TX	GLYCOL REBOILER, EPN11	13.31	2.5	MMBTU/H	NONE INDICATED	0.25	LB/H	
TX-0364	SALT CREEK GAS PLANT	TX	HP TEG FIREBOX, EPN30	13.31	3	MMBTU/H	NONE INDICATED	0.25	LB/H	
TX-0364	SALT CREEK GAS PLANT	TX	HOT OIL HEATER, EPN6	13.31	12	MMBTU/H	NONE INDICATED	1.19	LB/H	

Best Available Control Technology

Table A-5 Natural Gas-Fired Process Heater (<100 mmBtu/hr) RBLC CO Permit Limit Summary (2004 to present), continued

RBLC ID	FACILITY NAME	STATE	PROCESS NAME	PROCESS TYPE	THRUPUT	THRUPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	EMISSION LIMIT AVERAGING TIME
TX-0364	SALT CREEK GAS PLANT	TX	HOT OIL HEATER, EPN26	13.31	32.5	MMBTU/H	NONE INDICATED	3.21	LB/H	0.099 lb/mmBtu
TX-0388	SAND HILL ENERGY CENTER	TX	INLET AIR HEATERS (3)	13.31				0.44	LB/H	
TX-0392	LUCITE BEAUMONT	TX	NO.1 PRE-HEATER	13.31				1.6	LB/H	
TX-0392	LUCITE BEAUMONT	TX	NO. 2 PRE-HEATER	13.31				1.6	LB/H	
WA-0301	BP CHERRY POINT REFINERY	WA	PROCESS HEATER, IHT	13.31	13	MMBTU/H	GOOD COMBUSTION PRACTICES	70	PPM	7% O2, 24 hr ave
WI-0195	SENA NIAGARA MILL	WI	PROCESS HEATER, PAPER MACHINE P51	13.31	34.4	MMBTU/H	ANY NEW (REPLACEMENT) IR BURNERS WILL BE LOW NOX BURNERS, FIRING NATURAL GAS	0.06	LB/MMBTU	
WI-0223	LOUISIANA-PACIFIC HAYWARD	WI	THERMAL OIL HEATER, GTS ENERGY, S31, B31	13.31	32	MMBTU/H	USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE	2.7	LB/H	0.084 lb/mmBtu
WI-0223	LOUISIANA-PACIFIC HAYWARD	WI	THERMAL OIL HEATER, GTS ENERGY, S32, B32	13.31	32	MMBTU/H	USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE	2.7	LB/H	0.084 lb/mmBtu
WI-0227	PORT WASHINGTON GENERATING STATION	WI	GAS HEATER (P06, S06)	13.31	10	MMBTU/H	NATURAL GAS FUEL	0.47	LB/H	
WI-0228	WPS - WESTON PLANT	WI	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	13.31	0.75	MMBTU/H	NATURAL GAS	0.06	LB/H	
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 1	13.31	21	MMBTU/H	GOOD COMBUSTION PRACTICES	0.08	LB/MMBTU	HOURLY
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 2	13.31	21	MMBTU/H	GOOD COMBUSTION PRACTICES	0.08	LB/MMBTU	HOURLY
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 3	13.31	21	MMBTU/H	GOOD COMBUSTION PRACTICES	0.08	LB/MMBTU	HOURLY
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 4	13.31	21	MMBTU/H	GOOD COMBUSTION PRACTICES	0.08	LB/MMBTU	HOURLY
WY-0066	MEDICINE BOW IGL PLANT	WY	GASIFICATION PREHEATER 5	13.31	21	MMBTU/H	GOOD COMBUSTION PRACTICES	0.08	LB/MMBTU	HOURLY
WY-0067	ECHO SPRINGS GAS PLANT	WY	HOT OIL HEATER S38	13.31	84	MMBTU/H	GOOD COMBUSTION PRACTICES	0.02	LB/MMBTU	

Attachment B

Natural Gas-Fired Combined Cycle Post-Combustion CO Control Technology Cost Evaluation

Estimated capital costs and annual O&M costs associated with the CO oxidation catalyst control system are provided below:

Best Available Control Technology

Basin Electric Power Cooperative
Deer Creek Generating Station
Capital Cost Worksheet

Case	Units	Deer Creek Unit 1 1 x 1 x 1 NGCC (250 MW-gross without Duct Firing)	Notes
Gross Plant Output (MW-gross)	**MW-gross**	249.683	
Net Plant Output (MW-net)	**MW-net**	243.1760	For the cost effectiveness evaluation, used CT performance at full load heat input at average annual ambient conditions without duct firing.
Maximum Heat Input (mmBtu/hr)	**mmBtu/hr (HHV)**	1,710.4	
Combustion Turbine Exhaust Gas Flow Rate	**lb/hr**	3,489,000	
Baseline CO Emission Rate (lb/mmBtu)	**lb/mmBtu**	0.0167	Baseline CO emisison rate with combustion controls (DLNB)
Capacity Factor Used for Cost Estimates (%)	**%**	100%	Assumed 100% capacity factor at full load heat input without duct firing.
Capital Cost Recovery Factor Equipment Life	**years**	20	Assumed 20 year life of oxidation catalyst system.
Pretax marginal rate of return on private investment.	**%**	7%	Assumed 7% pretak marginal rate of return.

Capital Cost Estimates were based on published cost data available from control technolgoy vendors, cost estimates recently prepared for similiar projects, and cost estimates included in other recently submitted PSD permit applications for large NGCC units.

Option 1: Oxidation Catalyst Control System				
		Deer Creek Unit 1		
Cost Basis (Year)		2008		
Baseline CO Emission Rate	lb/mmBtu	0.0167		
Controlled CO Emission Rate (annual average)	lb/mmBtu	0.0044		
CO Catalyst System - Total Direct Capital Costs (TDCC). Includes frame, seals, instrumentation, initial catalyst, sales tax, freight, and direct installation costs (supports, handling & erection, electrical, piping, insulation, painting, etc.).	$	**$785,000**	$ 810	per lb/sec CT Exhaust Gas Flow Rate (Based on oxidation catalyst system cost estimates developed for similar sized natural gas-fired combined cycle units and vendor cost estimates).
Indirect Capital Costs				
General Facilities	$	$39,000	5%	Calculated as percent of Total Direct Capital Costs. Based on OAQPS Capital Cost Factors for an SCR system (Section 4, Chapter 2), and assuming that the same factors would apply for an Oxidation Catalyst system.
Engineering and Home Office Fees	$	$79,000	10%	
Process Contingency	$	$39,000	5%	
Startup and Performance Tests	$	$24,000	3%	
Total Indirect Installation Costs	$	**$181,000**		
Project Contingency	$	**$145,000**	15%	
Total Plant Cost	$	**$1,111,000**		
Preproduction Costs	$	$22,000	2%	
Total Capital Investment (TCI)	$	**$1,133,000**		
	$/kW-gross	$4.54		

Best Available Control Technology

	Deer Creek NGCC INPUT
Gross Plant Output (MW-gross)	**249.683**
Net Plant Output (MW-net)	**243.176**
Maximum Heat Input (mmBtu/hr)	**1,710.4**
Combustion Turbine Exhaust Gas Flow Rate (lb/hr)	**3,489,000**
Baseline NOx Emission Rate (lb/mmBtu)	**0.0167**
Post Low Nox Burner Emission Rate (lb/mmBtu)	**0.0044**
Capacity Factor used of Cost Estimates (%)	**100%**
Capital Cost Recovery Factor Equipment Life	**20**
Pretax marginal rate of return on private investment.	**7%**

CAPITAL COSTS			**Basis**
Total Capital Investment (TCI)	**$1,133,000**		TCR includes the Purchased Equipment Cost, Installation Costs, and Indirect Capital Costs such as engineering, contractor fees, and contingency. EPA Air Pollution Control Cost Manual 6th Ed., Section 1, Chapter 2, page 2-21.
Total Capital Investment ($/kW - gross)	$4.54		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0944		
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$107,000**		
OPERATING & MAINTENANCE COSTS			**Basis**
Variable Direct Annual Costs			
Reagent Cost	$0		NA
Annual Catalyst Replacement Cost	$137,000	$ 0.225 5	Based on catalyst system replacement cost of $0.225/lb/hr-flue gas flow, 5 year catalyst life, and future worth factor (OAQPS).
Auxiliary Power Cost	$173,000	1.5 $ 60	Based on 1.5 in. pressure drop across the Oxidation Catalyst, 220 kW/in. auxiliary power requirement, and $60/MWh power cost.
Total Variable O&M Cost	$310,000		
Semi-Variable Direct Annual Costs			
Additional Operators per shift	0.0	0	Assumed 0 additional operating or supervisory labor needed for the oxidation catalyst system.
Operating Labor	$0	$ 33.50	3 shift/day, 365 days/year @ $33.50/hour (salary + benefits) which is equal to an annual operator salary of $70,000/year.
Supervision	$0	15%	Assumed supervisory labor would equal 15% of operating labor.
Maintenance Labor and Materials	$17,000	1.50%	Assumed 1.5% of TCI based on OAQPS cost factor for SCR (Section 4, Chapter 2, page 2-45)
Total Direct Annual Costs	$17,000		
Indirect Annual Operating Cost			
Property Taxes	$11,300	1%	Calcualted as percentage of total capital investment (TCI). EPA Air Pollution Control Cost Manual 6th Ed., Section 1, Chapter 2, page 2-34.
Insurance	$11,300	1%	
Administration	$22,700	2%	
Total Indirect Operating Cost	$45,300		
Total Annual Operating & Maintenance Cost	**$372,300**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$107,000**		
Annual Operating & Maintenance Cost	**$372,300**		
Total Annual Cost	**$479,300**		

Best Available Control Technology

Basin Electric Power Cooperative
Deer Creek Generating Station
CO CONTROL SUMMARY

Annual Emission Summary

	Baseline CO Emissions			
NGCC Operating Mode	**ppmvd @ 15% O2**	**lb/hr**	**hours/year**	**tpy**
Full Load CT w/o Duct Firing	7.4	28.5	5,850	83.4
Full Load CT with Duct Firing	11.2	57.2	2,200	62.9
Startup/Shutdown CO Emissions			708	108
Total Annual CO Emissions			8,758	254.3

	Controlled CO Emissions (Oxidation Catalyst)			
NGCC Operating Mode	**ppmvd @ 15% O2**	**lb/hr**	**hours/year**	**tpy**
Full Load CT w/o Duct Firing	2.0	7.6	5,850	22.2
Full Load CT with Duct Firing	2.0	10.3	2,200	11.3
Startup/Shutdown CO Emissions			708	76.6
Total Annual CO Emissions				110.1

Option	Control Technology	Expected Emissions (ton/year)	Expected Emissions Reduction (ton/year)	Total Capital Requirement ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)
	Baseline Emissions (with Dry Low-NOx Burners)	254.3	NA					
1	Oxidation Catalyst	110.1	144.2	$1,133,000	$107,000	$372,300	$479,300	$3,324

Basin Electric Power Cooperative

Deer Creek Station
PSD Air Quality Construction Permit Application

Appendix D
Class II Air Dispersion Modeling Results

Prepared by:

Sargent & Lundy, LLC
Chicago, Illinois

May 29, 2009

Deer Creek Station
Class II Air Dispersion Modeling Results
May 29, 2009

Table of Contents

1 Introduction 2
2 Project Description 2
3 Project Location 2
4 Facility Equipment 2
4.1 Combustion Turbine/HRSG 3
4.2 Natural Gas-Fired Emergency Inlet Air Heater 4
4.3 Air-Cooled Condenser 4
4.4 Emergency Generator and Fire Water Pump 4
5 Model Selection and Input 4
5.1 Model Selection 4
5.2 Meteorological Data Selection 5
5.3 Model Setup and Application 5
5.3.1 AERMAP 5
5.3.2 AERMET 5
5.3.3 AERSURFACE 6
5.4 Receptors 6
5.5 Good Engineering Practice (GEP) Stack Height Analysis 6
5.6 Pollutants Subject to Review 7
5.7 Pollutant-specific Considerations 7
5.7.1 NO_x 7
5.7.2 $PM_{10}/PM_{2.5}$ 7
5.8 Emission Points 7
5.9 Load conditions and equipment operating schedules 7
5.9.1 Combustion Turbine/HRSG 7
5.9.2 Emergency Inlet Air Heater 8
5.9.3 Emergency Generator and Fire Water Pump 9
6 Class II Air Dispersion Modeling Methodology 9
6.1 Class II Air Dispersion Modeling Process 9
6.2 Significant Impacts Analysis and Results 10
6.3 AERMOD Input and Output Files 10
7 Class I Impacts 11
8 References 12

1 Introduction

Basin Electric Power Cooperative (BEPC) is planning to construct the Deer Creek Station (hereinafter referred to as the "Project"), a nominal 300-megawatt (MW) natural gas-fired combined-cycle plant near the town of White in Brookings County, SD. This document contains results of a Class II air quality modeling analysis submitted to the South Dakota Department of Environmental Quality and Natural Resources (DENR) Air Quality Division to support issuance of the proposed facility's air construction permit. The air quality analyses were completed following a modeling protocol submitted to DENR (BEPC, 2008). The air quality analysis conforms to procedures outlined be the U.S.EPA (2005(a) and U.S.EPA (1990)). This document is an appendix to BEPC's PSD Air Quality Construction Permit Application (or the "Permit Application" BEPC 2009).

2 Project Description

The Deer Creek Station will be a greenfield 300-MW (nominal) combined-cycle natural-gas fired power plant. The plant includes two turbine-generators: one natural gas-driven and the other steam-driven. It is anticipated that the station will use natural gas from Basin Electric's Dakota Gasification Company via the Northern Border Pipeline. The power station will be connected to existing transmission lines. The station is needed to meet growing member load requirements and will serve as an intermediate power supply, which is designed to cycle with demand. Project emissions will exceed PSD significant emission rates for NOx, CO, and PM (BEPC 2009).

3 Project Location

The Deer Creek Station will be located approximately 14 miles northeast of Brookings, SD and 6 miles southeast of White, SD in Brookings County, SD. The project site encompasses approximately 100 acres of agricultural land. The land use is predominantly rural under the Auer land-use scheme (Auer 1978). The approximate Universal Transverse Mercator coordinates of the facility are 696,451 m east and 4,918,630 m north (UTM zone 14, NAD 27 projection). The terrain around the site is slightly rolling; terrain elevations range from 1750 feett above mean sea level (AMSL) to 1860 feet AMSL around the project site. The location of the proposed facility is shown in Figure 1 and Figure 2. Brookings County is classified as being in attainment or unclassifiable for all National Ambient Air Quality Standards (NAAQS).

4 Facility Equipment

The proposed Deer Creek Station will be a natural gas-fired combined cycle plant. Major components of the facility include the combustion turbine (CT) and heat recovery steam generator (HRSG). Other emissions sources include a natural gas-fired emergency inlet air heater, a diesel-fired emergency generator, and diesel-fired fire-water pump. The facility layout, including the location of proposed emission sources, is shown in Figure 3. An elevation view of the CT/HRSG is shown in Figure 4.

4.1 Combustion Turbine/HRSG

The Deer Creek project will include one F-class (or equivalent) natural gas-fired combustion turbine and HRSG. In a gas turbine, large volumes of air are compressed and injected with natural gas into a combustion chamber. Combustion turbine emissions are controlled with low-NO_x burners and best combustion practices. The proposed CT includes an air compressor section, advanced natural gas combustion section, power turbine, and electric generator. Ambient air is drawn through an inlet air filter on the CT and compressed in a multiple-stage axial flow compressor. Compressed air and natural-gas are mixed and combusted in the CT combustion chamber.

Based on the Best Available Control Technology (BACT) analysis prepared for the proposed facility (BEPC 2009), dry low-NO_x combustors will be used to minimize NO_x formation during combustion. The HRSG will utilize hot combustion gases exiting the combustion turbine to produce steam. The HRSG will be equipped with natural gas-fired duct burners to generate additional steam during periods of peak electricity demand. Steam from the HRSG is used to drive a single steam turbine connected to an electrical generator. Exhaust gas from the HRSG passes through a Selective Catalytic Reduction (SCR) control system for additional NOx control prior to being discharged to the atmosphere through a single 150-foot stack.

The CT is designed to produce a nominal 166 MW of gross electrical power at full load and an average annual ambient temperature of 43 °F. Due to the dependence of air density (and mass of inflow combustion air) on temperature, CT power output decreases slightly as the ambient air temperature increases, and output increases as ambient air temperature decreases. The combustion turbine power output at full load will be range from approximately 150 MW at a summer temperature of 94 °F, to approximately 180 MW at a winter extreme temperature of -41 °F.

The HRSG used for the Deer Creek Station will be equipped with natural gas-fired duct burners. Heat input to the duct burners will depend on steam requirements and ambient conditions. Steam from the HRSG will drive a single steam turbine-generator with a nominal power output of 143 MW with duct firing and 84 MW without duct firing at the average annual ambient temperature of 43 °F. Steam turbine exhaust will be directed to an air cooled condenser, and the condensate will be re-used. Operating parameters for the CT/HRSG at base load and three ambient air temperatures (93 °F, 43 °F and -41 °F) and with/without supplemental duct firing are provided in BEPC (2009).

The CT/HRSG is cycled to follow changes in demand for electricity. Start-up emissions from the CT/HRSG are highly dependent upon how long the unit has been shut down. Start-ups are characterized as “cold”, “warm”, or “hot” depending upon the length of time that the CT/HRSG has been shut down. Start-up emissions are described in BEPC

(2009). The estimated total number of start-up hours per year is 708, or approximately 8.1% of a full year (BEPC 2009).

4.2 Natural Gas-Fired Emergency Inlet Air Heater

A natural-gas fired heater will be used to pre-heat the combustion turbine (CT) intake air during extremely cold ambient conditions (approximately -25 F, or colder). The heater will warm an ethylene glycol-water mixture that is piped to a heat exchanger located near the CT air intake. This heater would be used for approximately 10 to 20 minutes during start-ups under extreme ambient conditions until the CT is running at the appropriate speed. The heater is expected to operate a maximum of 150 hours per year.

4.3 Air-Cooled Condenser

Steam from the low-pressure (LP) section of the steam turbine will be condensed in an air cooled condenser (ACC) prior to being recycled. In the air cooled condenser, steam discharged from the turbine enters a steam distribution manifold located at the top of the ACC and is distributed to a number of finned-tube heat exchangers. The steam flows downward through the heat exchanger tubes and is condensed. Mechanical fans are used to force ambient air over the heat exchangers to cool the steam. The condensate is collected in a series of pipes located at the base of the heat exchangers and returned to the steam turbine water system. Because ambient air is the cooling medium, and there is no evaporation of cooling water into the ambient air, there are no emissions associated with the air cooled condensing system. Therefore, the ACC has not been identified as an emissions source at the Deer Creek Station and are not included in the air dispersion modeling.

4.4 Emergency Generator and Fire Water Pump

The Deer Creek Station will also have an emergency diesel generator (EDG) and emergency fire-water pump (FWP). During interruptions of the electrical power to the site, the EDG will supply power to the essential service motor control centers, building heat and fuel supply systems, plant communication systems, and essential emergency lighting. Both diesel engines will be designed to fire low-sulfur diesel fuel. The EDG and FWP are expected to operate less than 150 hours per year, including short periods (i.e., a maximum of 1-2 hours per week) for routine maintenance and testing.

5 Model Selection and Input

5.1 Model Selection

The U.S.EPA regulatory model AERMOD (version 07026; USEPA 2004(a)) was used to conduct the dispersion modeling analysis. AERMOD was considered to be the most appropriate guideline model for calculating ambient concentrations near the proposed plant based on AERMOD's ability to incorporate multiple sources and downwash effects.

AERMOD input files were assembled with standard text editors and the Version 6.1.0 of Lakes Environmental MS-Windows ISC-AERMOD-View© program. The interface was used for checking consistency among input files, managing AERMOD simulations and executing the AERMOD codes.

5.2 Meteorological Data Selection

Five-year (2000-2004) sequential hourly surface data from the Huron, SD Regional airport (WBAN #14936) were processed into AERMOD-compatible surface and profile data files by DENR. The Huron Regional airport is located approximately 80 miles (128 km) due west of the proposed facility in a similar rural setting and in the same climatic zone as the site (Trewartha 1961) so these data are representative of the meteorological conditions experienced at the project site. The station elevation of Huron (390.4 m above mean sea level) was used in AERMOD. The anemometer height at Huron for the 2000-2004 period of record is 10 m (NRCS, 2008) which was used in AERMET meteorological data processing (section 5.3.2). A wind rose from Huron, SD is shown in Figure 5.

Corresponding upper-air data were taken from Aberdeen, SD (WBAN #14929), which is located approximately 120 miles (193 km) northwest of the project location. The Aberdeen, SD upper-air station is considered to be the closest and most representative upper-air station.

5.3 Model Setup and Application

The AERMOD system consists of three main modules: the AERMOD air dispersion module; the AERMET meteorological data pre-processor; and the AERMAP terrain data pre-processor. The U.S.EPA recently released the AERSURFACE program (USEPA 2008 (a)) which prepares required land-use information inputs for AERMET. The application of each of these programs is discussed below.

5.3.1 AERMAP

The AERMAP terrain data pre-processor (version 09040; USEPA 2003) extracted receptor elevation data from 7.5-minute USGS Digital Elevation Model (DEM) files (USGS 2008(a)). AERMAP produced receptor heights and related parameters that were input into AERMOD via the ISC-AERMOD-View© interface. Receptor elevations were based on North American Datum 1927 (NAD27). The highest receptor was specified in AERMAP's hill-height algorithm. The grade elevations near the facility, as determined from the DEM files, were within approximately one meter of actual grade elevations.

5.3.2 AERMET

AERMOD uses boundary-layer parameters based on estimates of the surface albedo, Bowen ratio and surface roughness length (USEPA 2005(b)). DENR used the AERMET meteorological data pre-processor version 06341 (USEPA 2004(b)) to develop meteorological input data for AERMOD. The surface data came from Huron, SD and upper-air data came from Aberdeen, SD (section 5.2). AERMET produces AERMOD-compatible surface (*.sfc) and profile (*.pfl) text files. The surface and profile files were be concatenated into a single pair of input files for convenience.

5.3.3 AERSURFACE

DENR used the USEPA AERSURFACE program (version 08009; USEPA 2008(a)) to determine the surface albedo, Bowen ratio and surface roughness length from land use information. This information was used in the AERMET processor described above. Land use information was taken from the U.S. Geological Survey (USGS) and EPA National Land Cover Data (NLCD) data set (USGS 2008(b)).

5.4 Receptors

The air quality analysis used a nested receptor grid and a fenceline which were consistent with specifications in the air dispersion modeling protocol (BEPC 2008). It was necessary to slightly adjust the extent of the innermost nested grids to ensure that the maximum impacts were resolved with the 50-m or 100-m grids. The fenceline separated the on-site portion of the air shed from ambient air. The fenceline was defined using a 50-meter receptor spacing. Receptors enclosed by the fenceline were not included in the ambient air quality analysis.

The innermost (first) nested grid extended to approximately 800 meters from the fenceline in all directions. This grid had a 50-meter spacing. The second grid extended from approximately 800 m to 2,700 m from the fenceline and had a 100-meter spacing. The third grid extended from approximately 2,700 m to 5,200 m from the fenceline and had a 500-m receptor spacing. The outermost grid extended from 5,200-10,000 m from the fenceline and had a 1,000-m receptor spacing. The receptors are shown in Figure 6 and Figure 7. The fence line is shown in Figure 8. The resulting grid had 6,285 receptors. Receptor elevations from AERMAP (section 5.3.1) were input into AERMOD and checked using the MS-Windows ISC-AERMOD View© program.

5.5 Good Engineering Practice (GEP) Stack Height Analysis

A Good Engineering Practice (GEP) stack height analysis was conducted to include building wake effects in AERMOD. The EPA's BPIP-PRIME program (USEPA 2004(a); USEPA 1997) (version 04274) was used to conduct the analysis in accordance with USEPA (1985). BPIP-PRIME requires structure dimensions and locations from facility site general arrangement (GA) drawings. Heights of the structures included in the BPIP analysis are listed in Table 1. The locations of these structures are shown in Figure 8 and Figure 9. A 3-D rendering of the structures from BPIP-PRIME is shown in Figure 10. Output from BPIP-PRIME was input into AERMOD input files for dispersion analysis with the MS-Windows ISC-AERMOD View© program.

5.6 Pollutants Subject to Review

Only regulated NSR pollutants whose emissions increases exceed the PSD significant levels and are therefore subject to PSD review were evaluated in the modeling analysis. PSD significant emission rates and emission rates for the project are listed in Table 2. PSD emission rates were only exceeded for NO_x, CO, and PM. A detailed discussion of the project emission rates presented in Table 2 is given in BEPC (2009). NAAQS and PSD increments for criteria pollutants are listed for reference in Table 3 and Table 4.

5.7 Pollutant-specific Considerations

5.7.1 NO_x

Per discussion with DENR, modeled NO_x concentrations were directly compared as appropriate with the NO_2 PSD Increment and Modeling Significance Levels (Table 4). This is a conservative approach which assumes that all NO_x is converted to NO_2 (i.e., a NO_2/NO_x ratio of 1.0). This approach is more conservative than the approach often employed in Class II air quality analysis which uses a NO_2/NO_x ratio of 0.75 per EPA (2002).

5.7.2 $PM_{10}/PM_{2.5}$

Per discussion with DENR, PM_{10} emissions were treated as a surrogate for $PM_{2.5}$ emissions. This means that if modeled PM_{10} emissions did not exceed the modeling significance level (MSL) for PM_{10} (Table 4), then no PM_{10} or $PM_{2.5}$ NAAQS analyses (section 6.1) would be required. However, if the MSL for PM_{10} was exceeded, then a NAAQS analysis would be conducted for $PM_{2.5}$ by modeling PM_{10} emission rates for the point sources and $PM_{2.5}$ emission rates for fugitive sources. This $PM_{2.5}$ NAAQS analysis would compare modeled concentrations with $PM_{2.5}$ NAAQS. However, as discussed below (section 6), PM_{10} emissions did not exceed the MSL for PM_{10}. Therefore, no PM_{10} or $PM_{2.5}$ NAAQS analyses with additional off-site sources were required. Per discussion with DENR, the highest modeled PM_{10} concentrations were compared with the annual and 24-hour MSLs (1 $\mu g/m^3$ and 5 $\mu g/m^3$, respectively; Table 4).

5.8 Emission Points

The locations and selected stack parameters for the emission points in the project are listed in Table 5. These parameters were used in AERMOD. Emission rates for the criteria pollutants are discussed in the following sections.

5.9 Load conditions and equipment operating schedules

5.9.1 Combustion Turbine/HRSG

Air dispersion modeling was performed using differing combinations of operating conditions of the CT/HRSG based on averaging period (annual and short-term); load condition (25%, 50%, 75% and 100%) and atmospheric temperature (annual average of 43 °F; winter temperature of -41 °F; and summer temperature of 94 °F). The use of augmented (duct) firing was also evaluated for the 100% load conditions. This produced a combination of 17 load conditions for analyzing emissions with AERMOD. Three additional start-up conditions (hot, warm and cold start ups) were also modeled, for a total of 20 conditions. These conditions are summarized in Table 6. The corresponding maximum hourly emission rates for the CT/HRSG are shown in Table 7. Emission rates for the CT/HRSG are described in BEPC (2009).

Modeling NO_X emissions from CT/HRSG start-up sequences over annual averaging periods

NO_x only has a single (annual) averaging period and NAAQS (Table 3). Per discussion with DENR, modeling of NO_x emissions from start-up sequences considered NO_x emissions from full-load operations rather than elevated NO_x emission rates that occur during the short start-up sequences. Since the unit would not operate continuously, averaging periods that include a start-up and shutdown sequence would also include extended periods without NO_x emissions. As a result, the actual average NO_x emission rate calculated over a period spanning a shutdown through start-up is significantly less than normal, full-load emission rates. Because impacts from NO_x emissions are only considered over an annual averaging period, modeling results based on full-load operations over a year would be conservative and over-estimate annually-averaged impacts of NO_x emissions from start-ups.

Modeling PM and CO emissions from CT/HRSG start-up sequences over short averaging periods

To conservatively estimate impacts over short (24-hour, or less) averaging periods, the maximum hourly emission rates for cold, warm and hot start-ups were used to model PM and CO emission rates for short-term (24-, 8- and 1-hour) averaging periods. The maximum hourly emission rates for start-ups are shown in Table 8.

5.9.2 Emergency Inlet Air Heater

The inlet heater is expected to operate for short periods (approximately 10-20 minutes) during start-ups and only during extremely cold (approximately -25 F, or colder) ambient conditions. The unit is expected to operate less than 150 hours per year. For purposes of modeling dispersion over annual averaging periods, the maximum hourly emission rates were multiplied by 0.0171 (0.0171 = 150/8760) to simulate a maximum expected 150 hours of annual operation. Emission rates for the emergency inlet air heater are listed in Table 9.

The exhaust stack for the emergency inlet air heater would be located adjacent to the CT/HRSG (Figure 9) and is expected to be affected by building downwash from the

CT/HRSG and other structures. The stack from the heater has a rain cap. Per modeling guidance (USEPA 2007), the actual stack diameter, stack height and exit temperature (Table 9) were used, but the exit velocity was set to 0.001 m/s for modeling purposes.

5.9.3 Emergency Generator and Fire Water Pump

The facility will also have an emergency diesel generator (EDG) and fire-water pump (FWP). The EDG will supply power during an interruption of the electrical power supply to the site. The EDG and FWP are expected to operate less than 150 hours per year, including 1-2 hours, or less, per week for maintenance and testing. Maximum hourly emission rates for the EDG and FWP from BEPC (2009) are listed in Table 10.

For purposes of air dispersion modeling, the maximum hourly emission rates for the EDG and FWP were multiplied by 0.0833 (0.0833 = 2/24) to simulate a maximum expected operating time of two hours for routine testing in 24-hour averaging periods modeled in AERMOD. For annual averaging periods, the maximum hourly emission rates were multiplied by 0.0171 (0.0171 = 150/8760) to simulate a maximum expected 150 hours of operation annually. The maximum hourly emission rates were used for the shortest averaging periods (8- and 1-hr averaging periods for CO emissions). The resulting emission rates for EDG and FWP used in AERMOD are listed in Table 10. To produce conservative results, emissions from the EDG and FWP were included in all modeled load conditions.

6 Class II Air Dispersion Modeling Methodology

6.1 Class II Air Dispersion Modeling Process

Class II air dispersion modeling is conducted in two phases. The initial phase consists of a significant impacts analysis which compares the maximum impacts of a project with modeling significance levels (MSLs) (Table 4) for pollutants whose emissions exceeds PSD significance rates. BEPC anticipates that it will exceed PSD significant emission rates for NO_x, CO, and PM (Table 2). Depending upon the outcome of the initial phase, a second (refined) phase may follow which consists of PSD increment and NAAQS analyses that include emissions from sources at the proposed facility and surrounding facilities.

In the significant impacts analysis, the maximum modeled impacts under various load conditions are determined for each pollutant whose potential to emit exceeds the corresponding PSD significant emission rate. The load conditions, pollutants, averaging periods and stack exit velocities and emission rates used in AERMOD are compiled from preceding tables in Table 11. The modeled concentrations for a number of load scenarios are compared with pollutant-and averaging-period specific MSLs to determine significant impact areas.

In the second phase of Class II air dispersion modeling, pollutants whose impacts exceed the MSLs in the first phase are modeled using project-related sources, off-site sources and background concentrations. The resulting concentrations are compared with the NAAQS and PSD increments (Table 3 and Table 4) to demonstrate compliance.

6.2 Significant Impacts Analysis and Results

The maximum ambient air concentrations from AERMOD are listed in Table 12 through Table 16. The locations of the maximum concentrations for each pollutant are plotted for reference in Figure 11. The maximum concentrations were recorded within approximately 500 m of the fence line (or, on the fenceline). Since the innermost grid and fence line had a 50-meter resolution (section 5.4) the maximum concentrations were adequately resolved.

The highest modeled concentration for each pollutant and respective averaging period in Table 12 through Table 16 is identified in Table 17. For the significant impacts analysis, these concentrations are compared with their respective MSL. Table 17 shows that each maximum predicted concentration is below its respective MSL. Therefore, the proposed project will have insignificant impacts on the ambient air quality. Since the modeled maximum impacts are below their respective MSL, additional air quality modeling that compares impacts with NAAQS and PSD Increments (section 6.1) was not required.

Table 17 also compares the highest ambient air concentration for each pollutant with its respective de minimus monitoring exemption level. This table shows that maximum predicted ambient air concentration would remain below the de minimus monitoring exemption levels. Therefore, pre-construction monitoring would not be required for the project.

A separate comparative analysis of modeled $PM_{2.5}$ impacts with the NAAQS is provided for informational purposes only and does not include cumulative impacts that would be part of a formal PSD analysis since a PSD analysis was not required, as discussed above. For comparison with the $PM_{2.5}$ NAAQS, the maximum modeled 24-hour PM impact was added to a background $PM_{2.5}$ concentration. A background concentration recorded near City Hall in Brookings, SD was used. This $PM_{2.5}$ concentrations is likely higher that the actual background PM concentration expected in an isolated, rural area around the project site. The results are shown in Table 18. This table shows that the maximum modeled PM concentrations were below the $PM_{2.5}$ NAAQS.

6.3 AERMOD Input and Output Files

The AERMOD input and output files are listed for reference in Table 19. Digital copies of the files are contained in an attachment.

7 Class I Impacts

There are no Class I areas located within 400 km of the proposed facility. The closest Class I area is the Badlands National Park located in southwestern South Dakota, approximately 420 km (260 miles) to the west-southwest of the facility. No air quality impacts are expected from the proposed facility given the great distance.

8 References

Auer, A.H. Jr., "Correlation of Land Use and Cover with Meteorological Anomalies", Journal of Applied Meteorology, Vol. 17, pp. 636-643, Published by American Meteorological Society, Boston, Mass., May 1978.

Natural Resources Conservation Service (NRCS), U.S. Department of Agriculture "Anemometer heights." Available online from: http://www.wcc.nrcs.usda.gov/climate/windrose.html. Web site accessed in July 2008.

Basin Electric Power Cooperative. "*Deer Creek Generating Facility Air Dispersion Modeling Protocol.*" October, 2008.

Basin Electric Power Cooperative. "*Basin Electric Power Cooperative Deer Creek Station PSD Air quality Construction Permit Application.*" 2009.

South Dakota Department of Environment & Natural Resources (DENR). "South Dakota Ambient Air Monitoring Annual Network Plan 2007." Available online from: http://www.state.sd.us/denr/denr.html 83 pp.

Trewartha, G.T. *"The Earth's Problem Climates."* University of Wisconsin Press, 1961.

U.S. Environmental Protection Agency (USEPA). *"Guideline for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations)*". Report EPA-450/4-80-023R. June 7, 1985. Available on-line from: http://www.epa.gov/scram001/guidance/guide/gep.pdf

U.S. Environmental Protection Agency (USEPA), "Prevention of Significant Deterioration Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting", Draft October 1990, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., 1990.

U.S. Environmental Protection Agency (USEPA), "Workbook for Plume Visual Impact Screening and Analysis (Revised)", EPA-454/R-92-023, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., October 1992.

U.S. Environmental Protection Agency (USEPA), "Addendum to ISC3 User's Guide, the Prime Plume Rise and Building Downwash Model", Earth Tech, Inc. and Electric Power Research Institute (EPRI), November, 1997. Available online from: http://www.epa.gov/scram001/7thconf/iscprime/useguide.pdf

U.S. Environmental Protection Agency (USEPA), Memorandum from Daniel DeRoeck to Richard Daye, "Use of the Ambient Ratio Method for Modeling Significant Ambient Impacts of NO2", March 2002.

U.S. Environmental Protection Agency (USEPA), "Revised Draft User's Guide for the Aermod Terrain Preprocessor (Aermap)", April 2003.

U.S. Environmental Protection Agency (USEPA), "User's Guide for the AMS/EPA Regulatory Model – AERMOD", EPA-454/B-03-001, September 2004(a).

U.S. Environmental Protection Agency (USEPA), "User's Guide for the Aermod Meteorological Preprocessor (Aermet)", EPA-454/B03-002, November 2004(b).

U.S. Environmental Protection Agency (USEPA), "Appendix W to 40 CFR Part 51 - Guideline on Air Quality Models", 2005(a).

U.S. Environmental Protection Agency (USEPA), "AERMOD Implementation Guide". September, 27 2005. Available on-line from: http://www.epa.gov/scram001/7thconf/aermod/aermod_implmtn_guide.pdf. 2005(b).

U.S. Environmental Protection Agency (USEPA), "AERMOD Implementation Guide" AERMOD Implementation Workgroup. October 19, 2007.

U.S. Environmental Protection Agency (USEPA), "AERSURFACE User's Guide." EPA-454/B-08-001. http://www.epa.gov/scram001/7thconf/aermod/aersurface_userguide.pdf. January 2008. 2008(a).

U.S. Environmental Protection Agency (USEPA). Technology Transfer Network (TTN) Air Quality System (AQS). Data for Roberts County, SD monitor. Web site accessed in July, 2008. 2008(b).

U.S. Geological Survey (USGS), "1:24,000 Scale Digital Elevation Models (DEM)" Available online from: http://www.webgis.com/. 2008(a).

U.S. Geological Survey (USGS) and USEPA, Multi-resolution Land Characterization (MRLC) Consortium. "National Land Cover Data". MRLC Regional Land Cover Characterization Project of the USGS EROS Data Center (EDC), Sioux Falls, SD. Version 10-11-2000. Data available on-line from: http://www.webgis.com/. 2008(b).

Figures and Tables

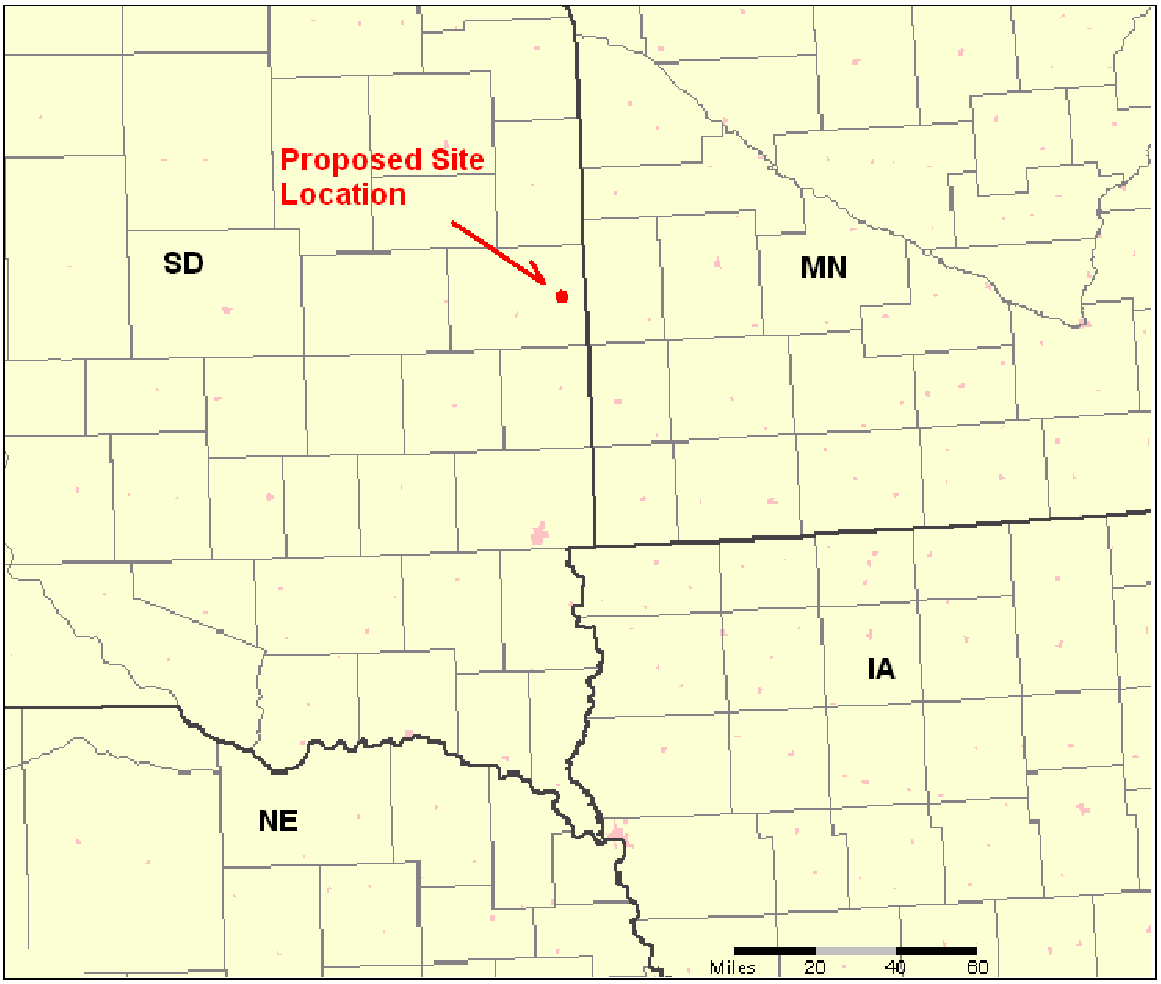


Figure 1. General location of the proposed Deer Creek Station.

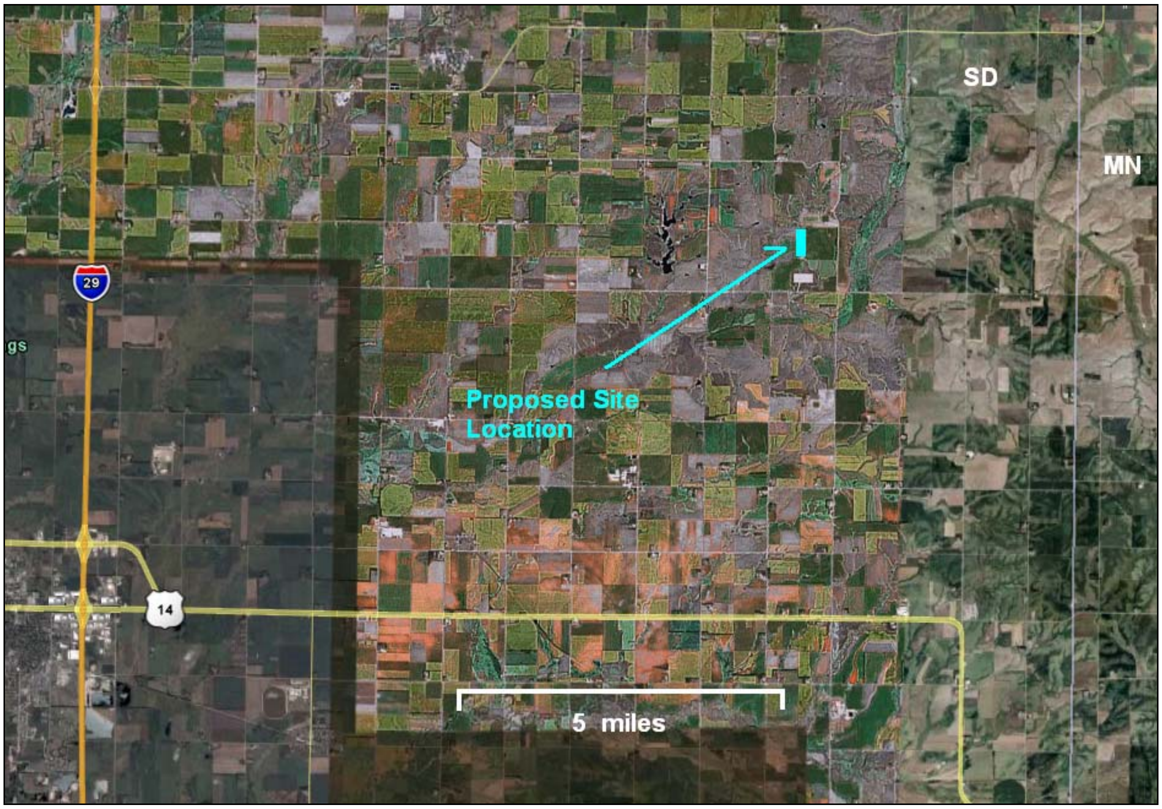


Figure 2. Specific location of the proposed Deer Creek Station.

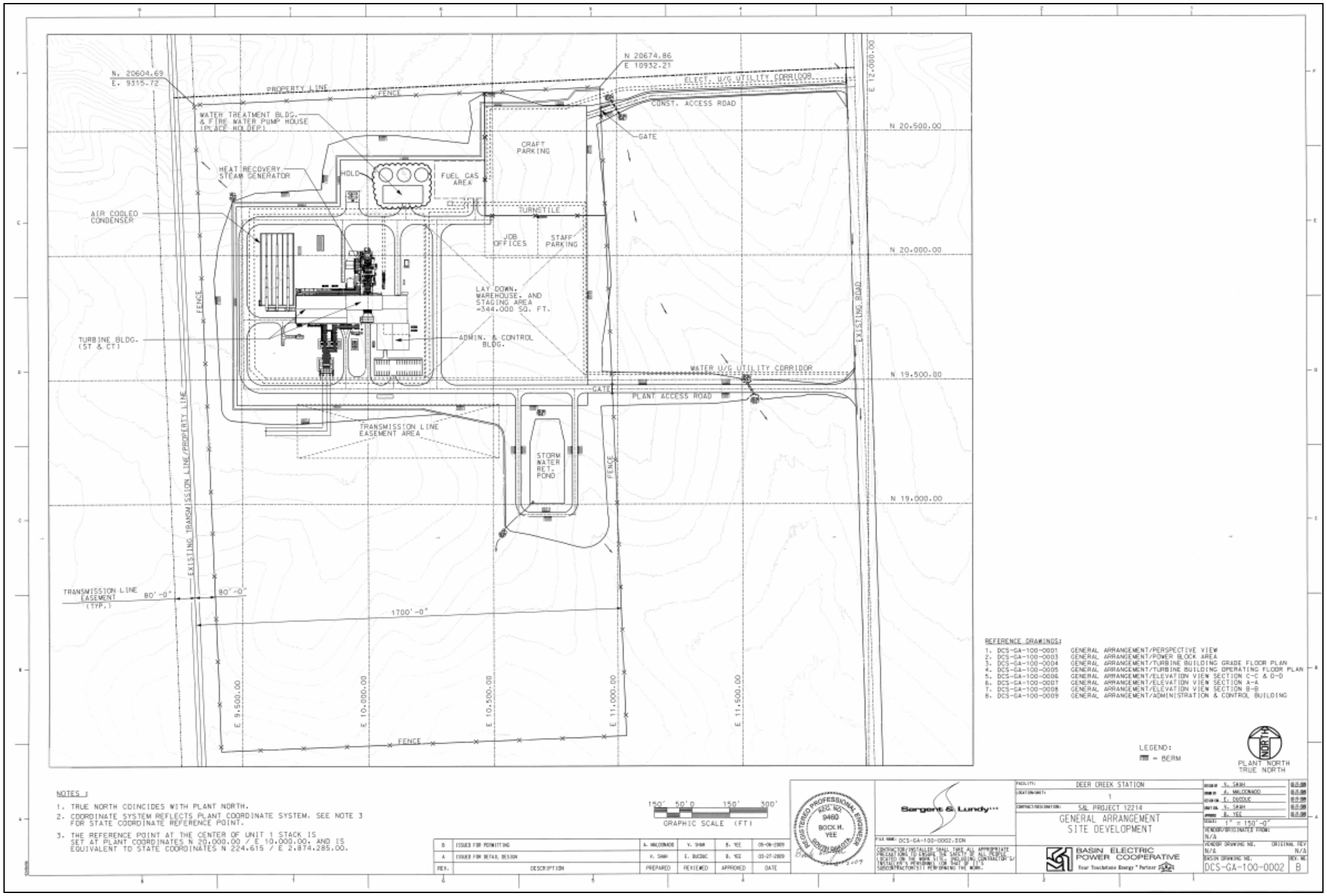


Figure 3. Site general arrangement (GA) diagram.

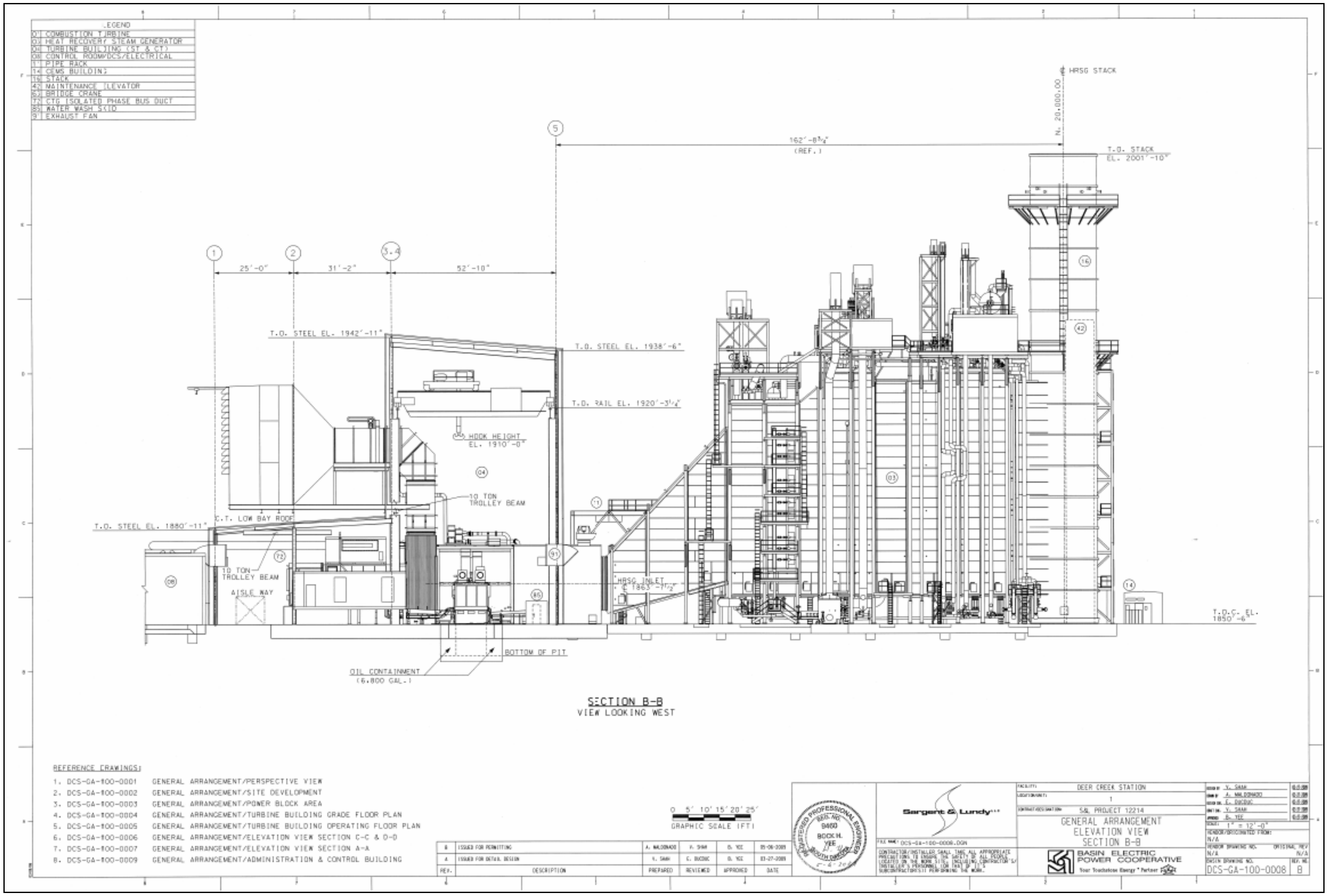


Figure 4. Elevation view of combustion turbine and HRSG.

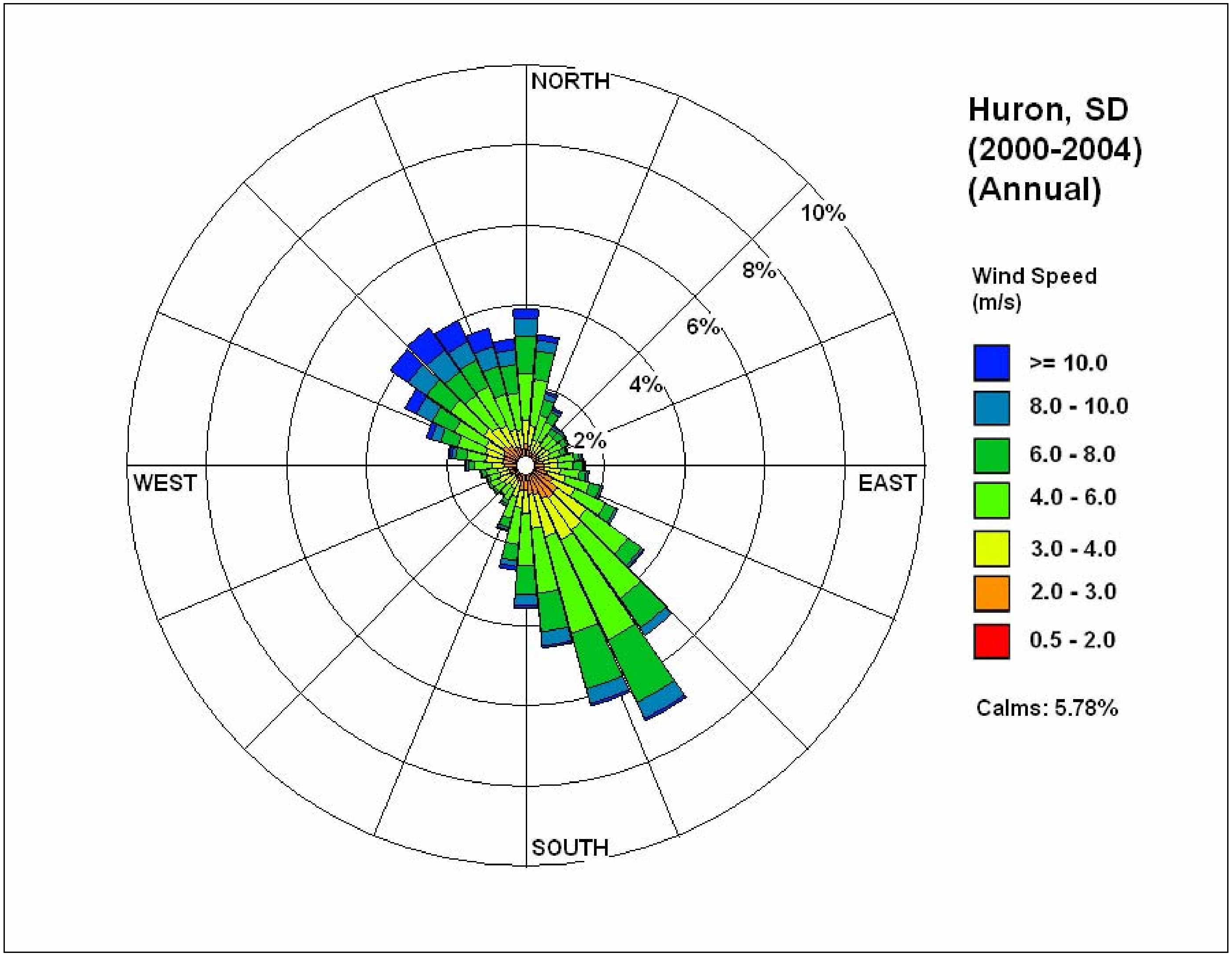


Figure 5. Wind rose from Huron, SD. (Data processed by DENR and plotted with ISC-AERMOD-View©).

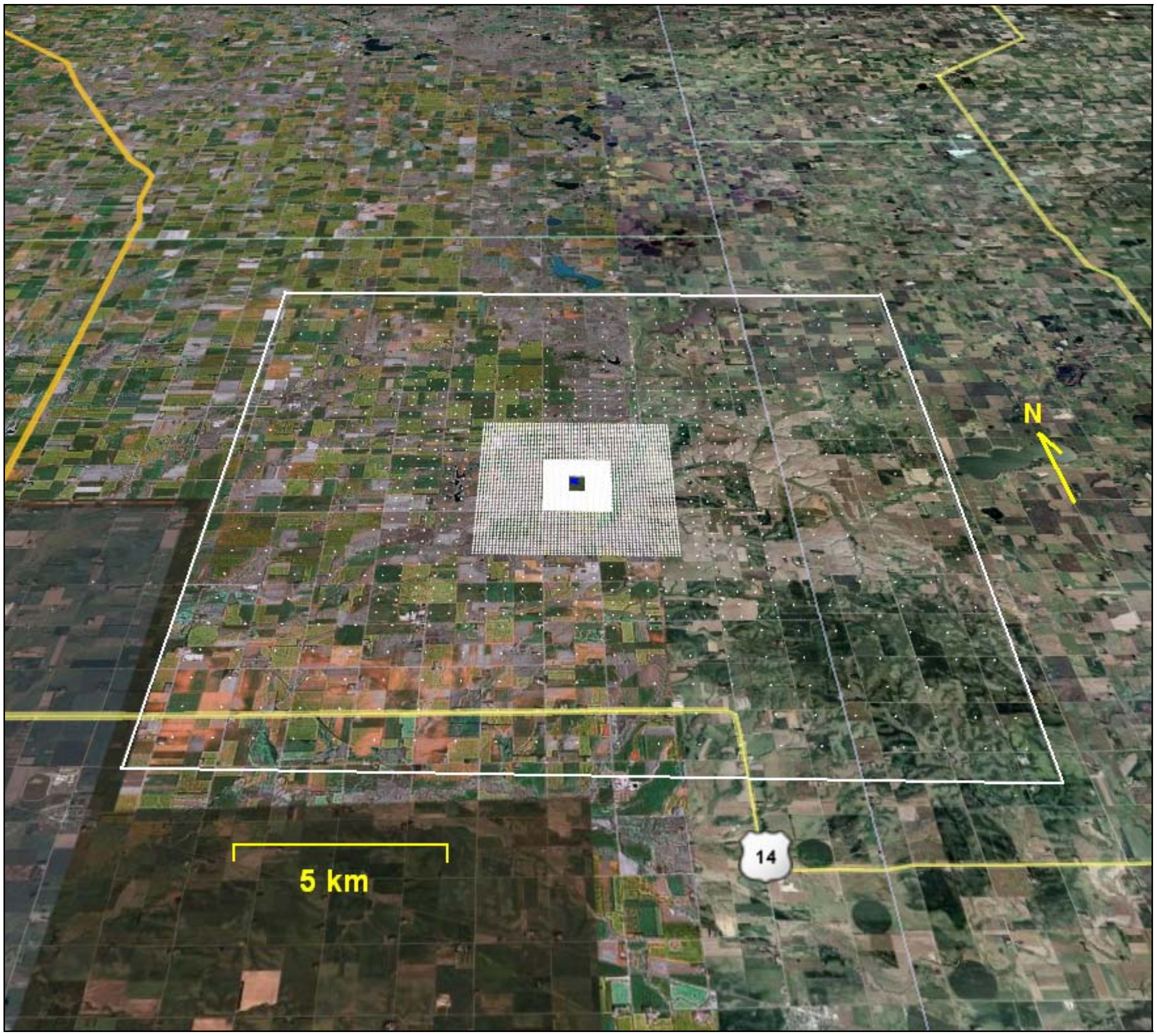


Figure 6. AERMOD receptor grid (outlined in white) and surrounding region looking north. (From AERMOD-ISC View© and Google-Earth map projection).

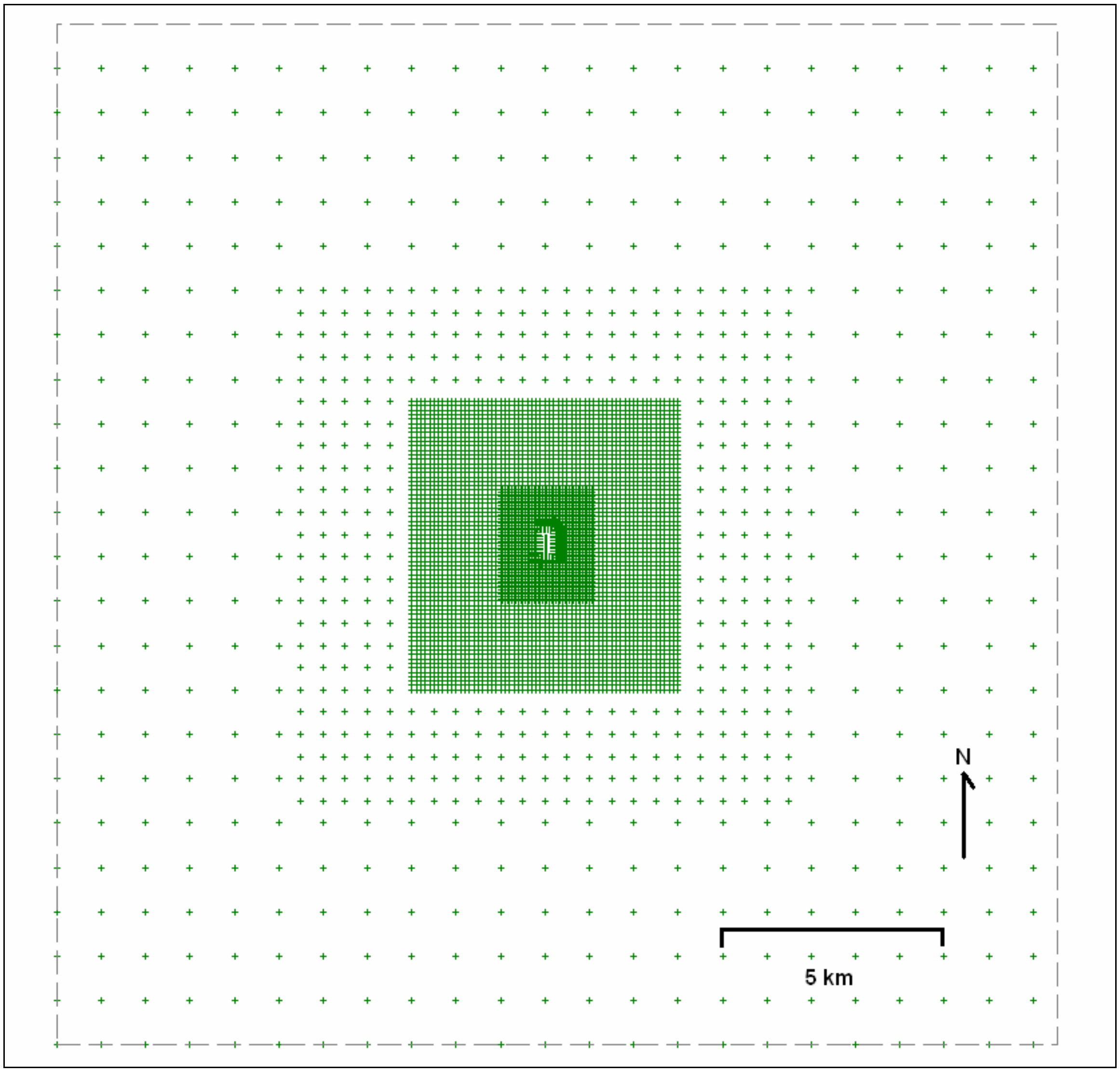


Figure 7. AERMOD receptor grid from Figure 6.

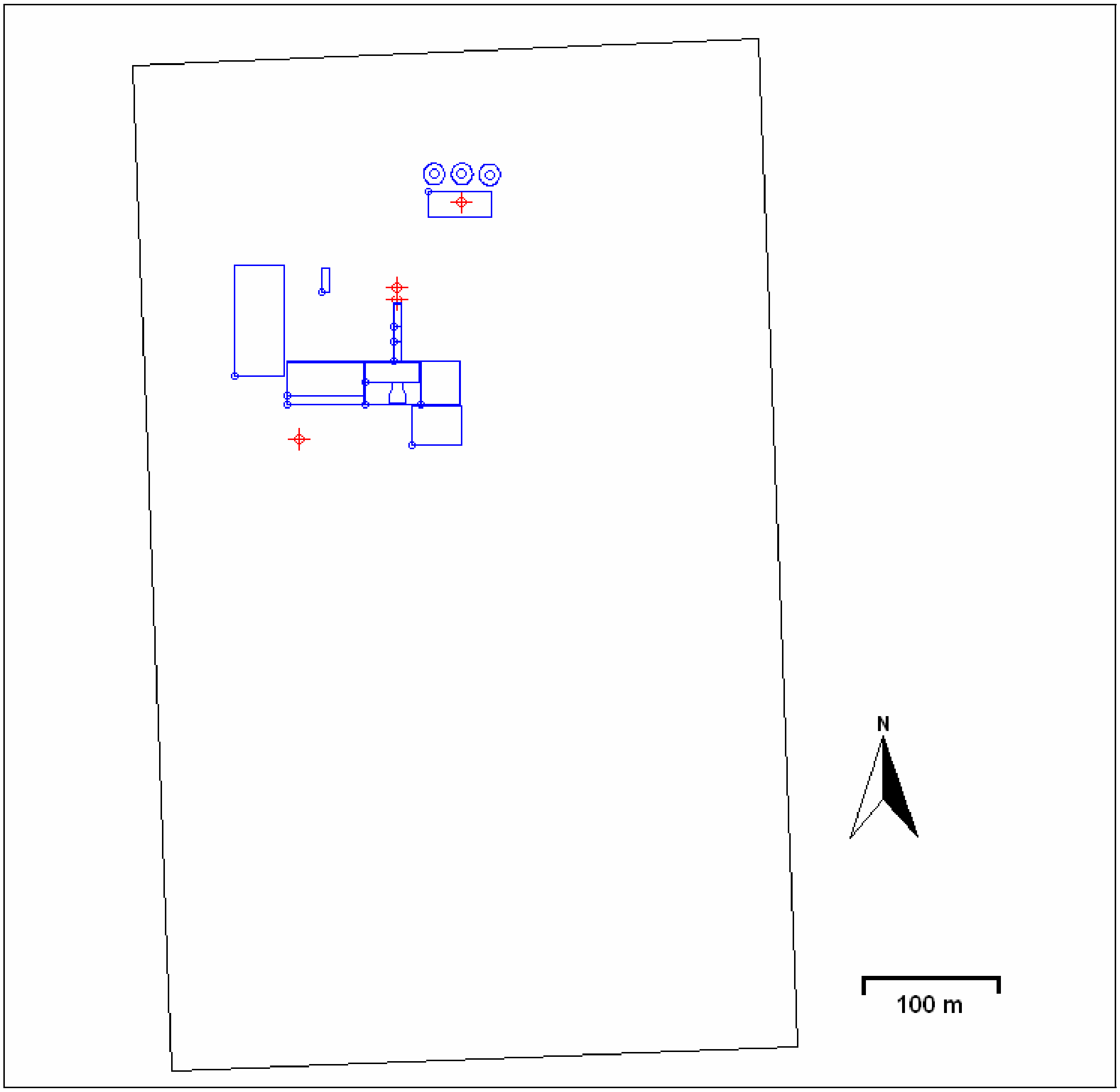


Figure 8. Plan view showing facility fence line, prominent structures included in BPIP-PRIME (blue) and sources (red).

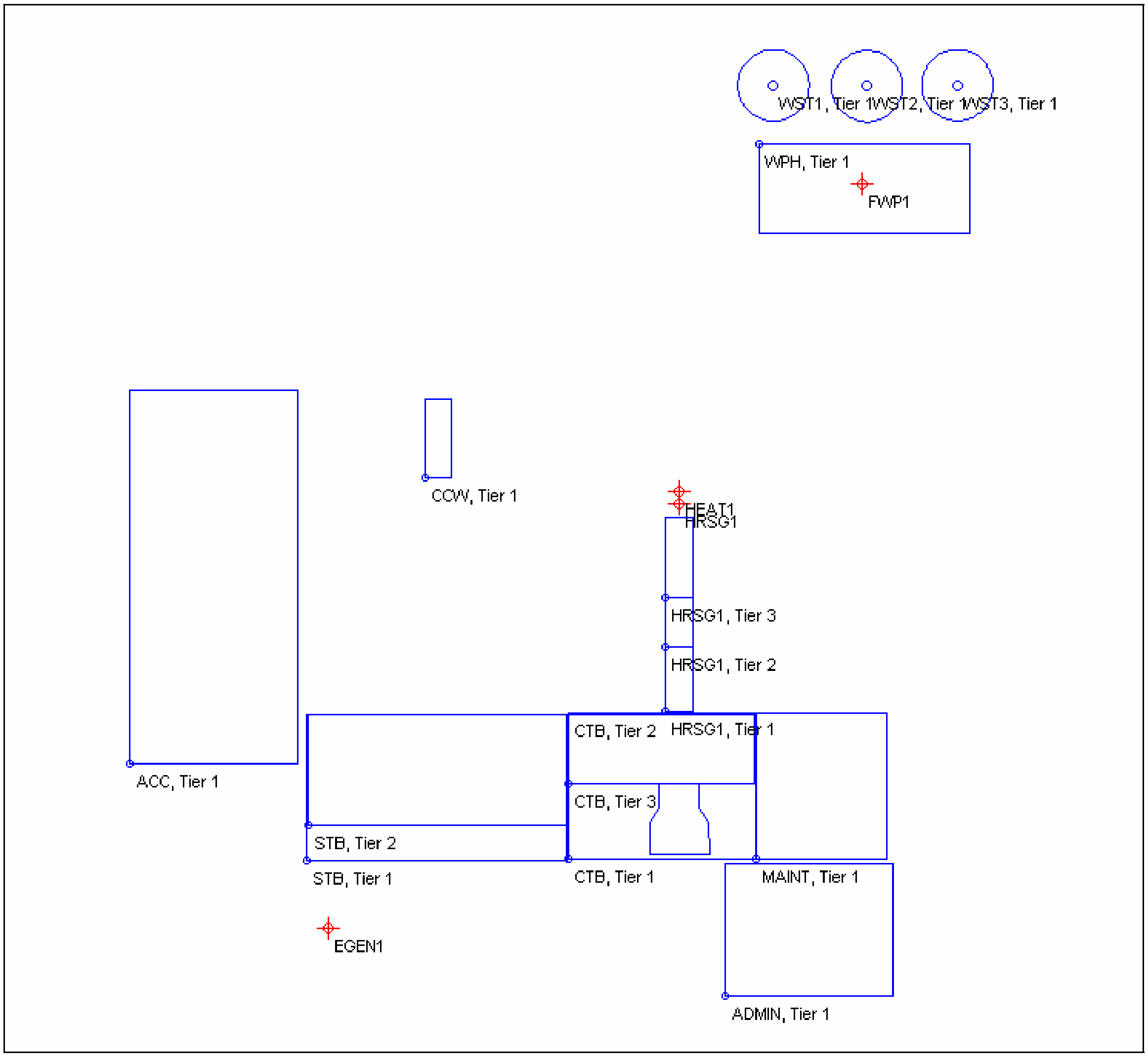


Figure 9. Close-up plan view from Figure 8 showing structures (blue) and point sources (red).

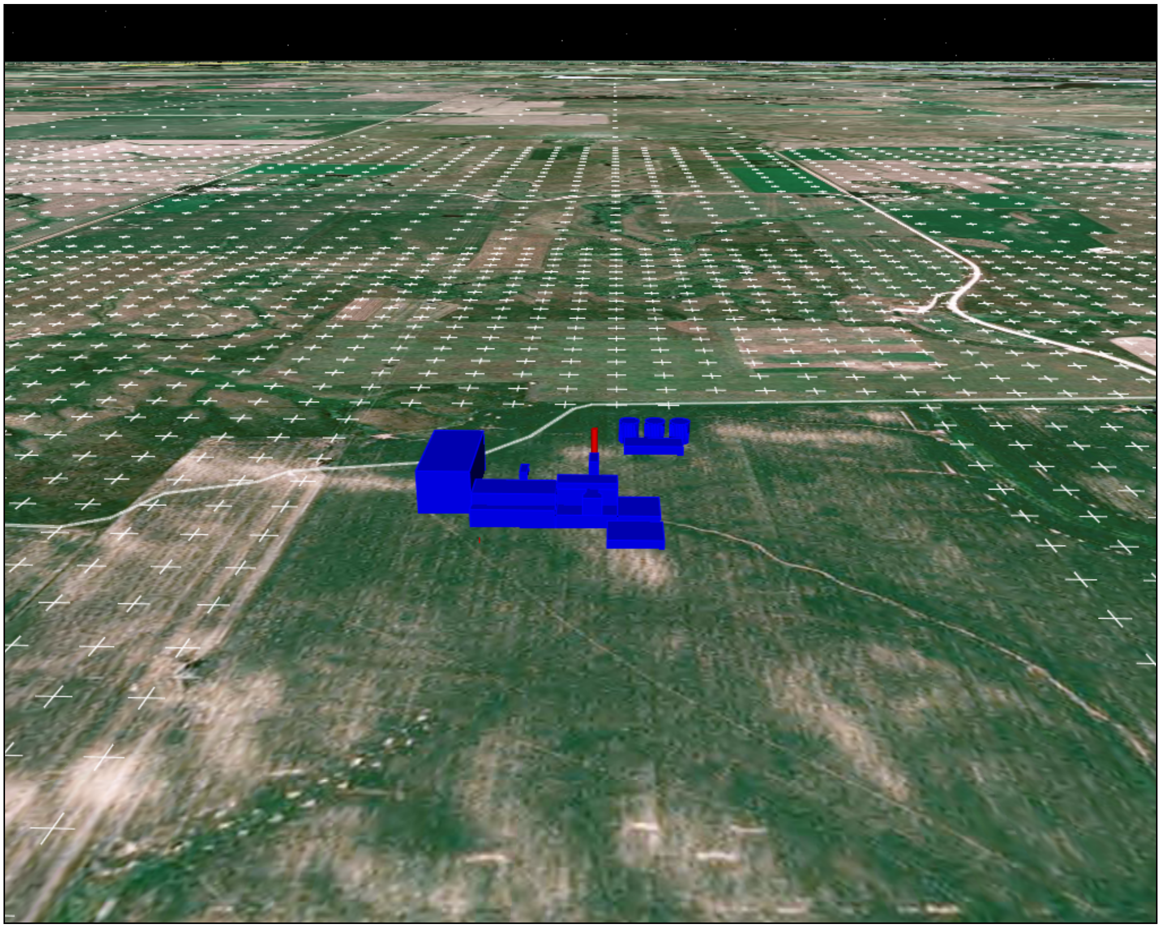


Figure 10. 3-D rendering of structures (blue) and point sources (red) from Figure 9, looking due north. White "+" signs represent discrete receptors shown in Figure 6 and Figure 7. The HRSG/CT stack is in red. (Output from AERMOD-ISC View© transformed to a Google-Earth map projection).

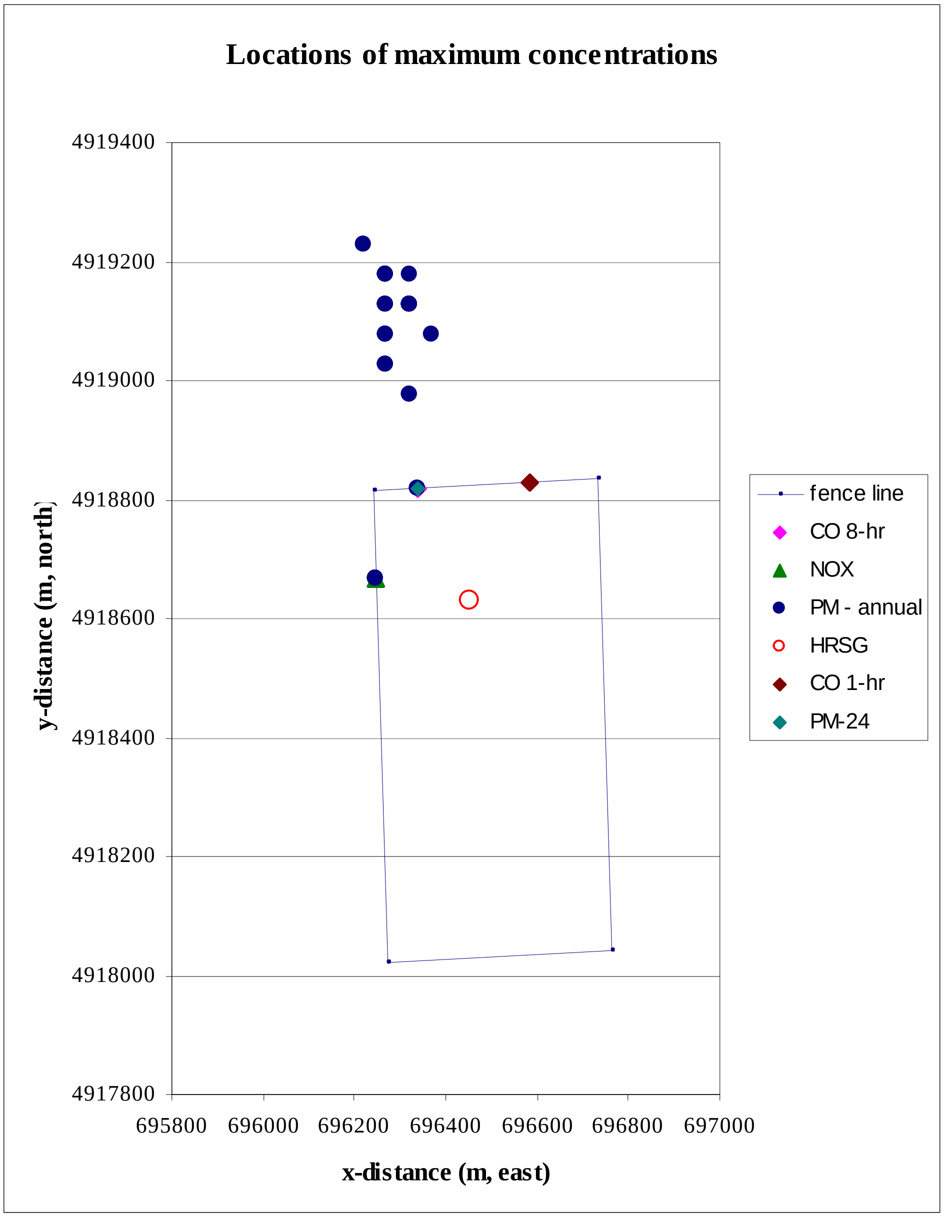


Figure 11. Fence line (blue), CT/HRSG and locations of maximum modeled concentrations listed in Table 12 - Table 15.

Table 1. Structures used in BPIP-PRIME downwash analysis

Building	Description	Grade elevation		Number of tiers		Height	
		ft/m				ft/m	
HSRG1	Heat recovery steam generator	1850.5	564	4	1	24.9	7.6
					2	54.0	16.5
					3	88.0	26.8
CCW	CCW heat exchanger	1850.5	564	1	1	20.0	6.1
ACC	Air cooled condenser	1850.5	564	1	1	110.0	33.5
WPH	Water treatment pump house	1850.5	564	1	1	25.0	7.6
WST1	Water storage tank	1850.5	564	1	1	60.0	18.3
WST2	Water storage tank	1850.5	564	1	1	60.0	18.3
WST3	Water storage tank	1850.5	564	1	1	60.0	18.3
STB	Steam turbine building	1850.5	564	2	1	45.0	13.7
					2	75.0	22.9
CTB	Combustion turbine building	1850.5	564	3	1	33.2	10.1
					2	75.0	22.9
					3	92.0	28.0
MAINT	Maintenance shop	1850.5	564	1	1	33.2	10.1
ADMIN	Administration building and control room	1850.5	564	1	1	21.0	6.4

Table 2. Comparison of PSD significant emission rates and expected annual emissions (from BEPC 2009)

NSR Regulated Pollutants	PSD Significant Level	Deer Creek Station Potential-to-Emit (PTE)	Does PTE Exceed the Significant Level?
	(tpy)	(tpy)	(Yes / No)
Carbon Monoxide	**100**	**256.0**	**Yes**
Nitrogen Oxides	**40**	**119.1**	**Yes**
Sulfur Dioxide	40	11.7	No
PM (total)	**25**	**80.1**	**Yes**
PM_{10} (total)	**15**	**80.1**	**Yes**
$PM_{2.5}$ (total)	**10**	**80.1**	**Yes**
Ozone (VOC)	40	29.7	No
Lead	0.6	3.60×10^{-4}	No
Sulfuric Acid Mist	7	2.21	No

Table 3. Primary and secondary NAAQS concentrations

	Primary Standards		Secondary Standards	
Pollutant	**Level**	**Averaging Time**	**Level**	**Averaging Time**
Carbon Monoxide	9 ppm ($10\ mg/m^3$)	8-hour (1)	None	
	35 ppm ($40\ mg/m^3$)	1-hour (1)		
Lead	$0.15\ \mu g/m^3$ (2)	Rolling 3-Month Average	Same as Primary	
	$1.5\ \mu g/m^3$	Quarterly Average	Same as Primary	
Nitrogen Dioxide	0.053 ppm ($100\ \mu g/m^3$)	Annual (Arithmetic Mean)	Same as Primary	
Particulate Matter (PM_{10})	$150\ \mu g/m^3$	24-hour (3)	Same as Primary	
Particulate Matter ($PM_{2.5}$)	$15.0\ \mu g/m^3$	Annual (4) (Arithmetic Mean)	Same as Primary	
	$35\ \mu g/m^3$	24-hour (5)	Same as Primary	
Ozone	0.075 ppm (2008 std)	8-hour (6)	Same as Primary	
	0.08 ppm (1997 std)	8-hour (7)	Same as Primary	
	0.12 ppm	1-hour (8) (Applies only in limited areas)	Same as Primary	
Sulfur Dioxide	0.03 ppm	Annual (Arithmetic Mean)	0.5 ppm ($1300\ \mu g/m^3$)	3-hour (1)
	0.14 ppm	24-hour (1)		

(1) Not to be exceeded more than once per year.
(2) Final rule signed October 15, 2008.
(3) Not to be exceeded more than once per year on average over 3 years.
(4) To attain this standard, the 3-year average of the weighted annual mean $PM_{2.5}$ concentrations from single or multiple community-oriented monitors must not exceed $15.0\ \mu g/m^3$.
(5) To attain this standard, the 3-year average of the 98^{th} percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed $35\ \mu g/m^3$ (effective December 17, 2006).
(6) To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm. (effective May 27, 2008)
(7) (a) To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm.
(b) The 1997 standard—and the implementation rules for that standard—will remain in place for implementation purposes as EPA undertakes rulemaking to address the transition from the 1997 ozone standard to the 2008 ozone standard.
(8) (a) The standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is ≤ 1.
(b) As of June 15, 2005 EPA revoked the 1-hour ozone standard in all areas except the 8-hour ozone non-attainment Early Action Compact (EAC) Areas.

Table 4. Allowable PSD Increments and Modeling Significance Levels ($\mu g/m^3$)

Pollutant	Averaging Time	PSD Increments		Modeling Significance Levels
		Class I	Class II	Class II
PM10	Annual Arithmetic Mean	4	17	1
	24-hour Maximum	8	30	5
SO_2	Annual Arithmetic Mean	2	20	1
	24-hour Maximum	5	91	5
	3-hour Maximum	25	512	25
CO	8-hour Maximum	NA	NA	500
	1-hour Maximum	NA	NA	2,000
NO_x	Annual Arithmetic Mean	2.5	25	1

NA = Not applicable – no standard exists for this pollutant and averaging time.
Source: 40 CFR 52.21, 40 CFR 51.165

Table 5. Stack parameters for the CT/HRSG, emergency generator and fire water pump

Source (AERMOD source name)	UTM (E)	UTM (N)	Grade elevation (ft/m)		Stack height (ft/m)		Stack diameter (ft/m)		Stack temp. (deg. F/K)	
	(UTM zone 14, NAD 27)									
CT/HRSG (HRSG1)	696,451.0	4,918,630.0	1850.5	564.03	150	45.72	19.00	5.79	200	366.48
Air Inlet Heater (HEAT1)	696451.0	4918633.0	1850.5	564.03	30	9.14	1.55	0.47	300	422.04
Emergency generator (EGEN1)	696,368.7	4918530.5	1850.5	564.03	15	4.57	1.43	0.43	850	727.59
Fire water pump (FWP1)	696494.0	4918705.4	1850.5	564.03	30	9.14	0.61	0.18	850	727.59

Table 6. Load conditions for the CT/HRSG

Modeling scenario	Purpose	Averaging period	Temperature (F)	Load	Duct-firing
1	Maximum annual average emissions	Annual	43	100%	On
2	Maximum annual average emissions	Annual	43	100%	Off
3	Maximum annual average emissions	Annual	43	75%	Off
4	Maximum annual average emissions	Annual	43	50%	Off
5	Maximum annual average emissions	Annual	43	25%	Off
6	Maximum short-term emissions	Short-term[1]	43	100%	On
7	Maximum short-term emissions	Short-term	94	100%	On
8	Maximum short-term emissions	Short-term	-41	100%	On
9	Maximum short-term emissions	Short-term	43	100%	Off
10	Maximum short-term emissions	Short-term	94	100%	Off
11	Maximum short-term emissions	Short-term	-41	100%	Off
12	Maximum short-term emissions	Short-term	43	75%	Off
13	Maximum short-term emissions	Short-term	94	75%	Off
14	Maximum short-term emissions	Short-term	43	50%	Off
15	Maximum short-term emissions	Short-term	94	50%	Off
16	Maximum short-term emissions	Short-term	43	25%	Off
17	Maximum short-term emissions	Short-term	94	25%	Off
18	Start-up (cold)	Short-term, annual	43	Start-up	Start-up
19	Start-up (warm)	Short-term, annual	43	Start-up	Start-up
20	Start-up (hot)	Short-term, annual	43	Start-up	Start-up

1 “Short-term” averaging periods refer to 24-, 8- and 1-hr averaging periods in this analysis.

Table 7. Load conditions and corresponding stack exit velocity and maximum hourly emission rate for the CT/HRSG (from BEPC 2009)

Load Condition	Ambient temperature (F)	Pollutant	Stack parameters			
			Exit velocity		Maximum hourly emission rate	
			feet/s	m/s	lb/hr	g/s
100% load + duct firing	43	NOX	62.6	19.0805	29.20	3.6791
100%	43	NOX	61.9	18.8671	21.80	2.7468
75%	43	NOX	49.3	15.0266	17.80	2.2428
50%	43	NOX	40.5	12.3444	14.00	1.7640
25%	43	NOX	32.3	9.8450	9.60	1.2096
100% load + duct firing	43	CO	62.6	19.0805	57.20	7.2071
100% load + duct firing	94	CO	58.7	17.8918	59.90	7.5473
100% load + duct firing	-41	CO	69.4	21.1531	48.70	6.1361
100%, no duct firing	43	CO	61.9	18.8671	28.50	3.5909
100%, no duct firing	94	CO	57.8	17.6174	26.00	3.2759
100%, no duct firing	-41	CO	69.0	21.0312	32.00	4.0319
75%	43	CO	49.3	15.0266	22.70	2.8602
75%	94	CO	45.8	13.9598	20.80	2.6208
50%	43	CO	40.5	12.3444	18.50	2.3310
50%	94	CO	38.5	11.7348	17.60	2.2176
25%	43	CO	32.3	9.8450	15.10	1.9026
25%	94	CO	31.1	9.4793	14.30	1.8018
100% load + duct firing	43	PM	62.6	19.0805	22.90	2.8854
100% load + duct firing	94	PM	58.7	17.8918	23.20	2.9232
100% load + duct firing	-41	PM	69.4	21.1531	22.30	2.8098
100%, no duct firing	43	PM	61.9	18.8671	16.70	2.1042
100%, no duct firing	94	PM	57.8	17.6174	15.70	1.9782
100%, no duct firing	-41	PM	69.0	21.0312	18.60	2.3436
75%	43	PM	49.3	15.0266	13.60	1.7136
75%	94	PM	45.8	13.9598	12.20	1.5372
50%	43	PM	40.5	12.3444	10.90	1.3734
50%	94	PM	38.5	11.7348	9.80	1.2348
25%	43	PM	32.3	9.8450	7.50	0.9450
25%	94	PM	31.1	9.4793	6.90	0.8694

Stack exit temperature (deg. F/K)	200	366.483
Stack height (ft/m)	150	45.72
Stack diameter (ft/m)	19.0	5.791

Table 8. Start-up maximum hourly emissions from the CT/HRSG (from BEPC 2009)

"Cold" start-up emissions	Total emissions (lbs)	Start up time (min)	Start up time (hr)	Emission rate (lb/hr)	Emission rate (g/s)
Pollutant					
CO	836.7	202	3.37	248.5	31.3136
NOX	221.6	202	3.37	65.5	8.2934
PM10	8.27	202	3.37	2.46	0.3095
Average exit velocity (ft/s, m/s)	43.6	13.2893			

"Warm" start-up emissions	Total emissions (lbs)	Start up time (min)	Start up time (hr)	Emission rate (lb/hr)	Emission rate (g/s)
Pollutant					
CO	550.6	98	1.63	337.1	42.4741
NOX	87.9	98	1.63	53.8	6.7807
PM10	3.26	98	1.63	2.0	0.2515
Average exit velocity (ft/s, m/s)	37.3	11.369			

"Hot" start-up emissions	Total emissions (lbs)	Start up time (min)	Start up time (hr)	Emission rate (lb/hr)	Emission rate (g/s)
Pollutant					
CO	346.60	63	1.05	330.1	41.5913
NOX	66.20	63	1.05	63.0	7.9439
PM10	1.96	63	1.05	1.87	0.2352
Average exit velocity (ft/s, m/s)	37.9	11.5519			

Table 9. Maximum hourly emission rates and stack parameters for the emergency inlet air heater (from BEPC 2009)

Averaging period	Pollutant	Maximum hourly emission rate			Emission rate used in AERMOD	
		lb/hr	g/s	Scaling factor	lb/hr	g/s
annual	NOX	2.45	0.3087	0.0171	0.0420	0.0053
short term	CO	2.06	0.2596	1.0000	2.0600	0.2596
annual	PM	0.19	0.0239	0.0171	0.0033	0.0004
short term	PM	0.19	0.0239	1.0000	0.1900	0.0239

Stack exit temperature (deg. F/K)	300	422.04
Stack height (ft/m)	30	9.14
Exit velocity (fps / m/s)	85	25.91
Stack diameter (ft/m)	1.55	0.47

Table 10. Maximum hourly emission rates and modeled emission rates for the emergency diesel generator and fire water pump (from BEPC 2009)

Averaging period	Pollutant	Emergency Generator					Fire Water Pump				
		Maximum hourly emission rate			Emission rate in AERMOD		Maximum hourly emission rate			Emission rate in AERMOD	
		lb/hr	g/s	Scaling factor	lb/hr	g/s	lb/hr	g/s	Scaling factor	lb/hr	g/s
annual	NOX	28.9000	3.6413	0.0171	0.4949	0.0624	2.3900	0.3011	0.0171	0.0409	0.0052
short term	CO	16.8000	2.1168	1.0000	16.8000	2.1168	3.3100	0.4171	1.0000	3.3100	0.4171
annual	PM	0.9700	0.1222	0.0171	0.0166	0.0021	0.1900	0.0239	0.0171	0.0033	0.0004
short term	PM	0.9700	0.1222	0.0833	0.0808	0.0102	0.1900	0.0239	0.0833	0.0158	0.0020

	Emergency Generator		Fire Water Pump	
Stack exit temperature (deg. F/K)	987	803.71	845	724.82
Stack height (ft/m)	15	4.572	30	9.144
Exit velocity (fps / m/s)	135	41.148	135	41.148
Stack diameter (ft/m)	1.425	0.434	0.607	0.185

Table 11. Modeled emission rates used in AERMOD

CT/HRSG Load condition	AERMOD averaging period	Temp. (F)	Pollutant	CT/HRSG		Air Inlet Heater		Emergency Diesel Generator		Fire Water Pump		AERMOD input files (*.adi)
				exit velocity	emission rate	exit velocity	emission rate	exit velocity	emission rate	exit velocity	emission rate	
				m/s	g/s	m/s	g/s	m/s	g/s	m/s	g/s	
100% load + duct firing	annual	43	NOX	19.0805	3.6791	0.0010	0.0053	41.148	0.0624	41.148	0.0052	aa10nxx
100%	annual	43	NOX	18.8671	2.7468	0.0010	0.0053	41.148	0.0624	41.148	0.0052	aa10nxxu
75%	annual	43	NOX	15.0266	2.2428	0.0010	0.0053	41.148	0.0624	41.148	0.0052	aa75nxx
50%	annual	43	NOX	12.3444	1.7640	0.0010	0.0053	41.148	0.0624	41.148	0.0052	aa50nxx
25%	annual	43	NOX	9.8450	1.2096	0.0010	0.0053	41.148	0.0624	41.148	0.0052	aa25nxx
100% load + duct firing	short term	43	CO	19.0805	7.2071	0.0010	0.2596	41.148	2.1168	41.148	0.4171	sa10call
100% load + duct firing	short term	94	CO	17.8918	7.5473	0.0010	0.2596	41.148	2.1168	41.148	0.4171	ss10call
100% load + duct firing	short term	-41	CO	21.1531	6.1361	0.0010	0.2596	41.148	2.1168	41.148	0.4171	sn10call
100%, no duct firing	short term	43	CO	18.8671	3.5909	0.0010	0.2596	41.148	2.1168	41.148	0.4171	sa10callu
100%, no duct firing	short term	94	CO	17.6174	3.2759	0.0010	0.2596	41.148	2.1168	41.148	0.4171	ss10callu
100%, no duct firing	short term	-41	CO	21.0312	4.0319	0.0010	0.2596	41.148	2.1168	41.148	0.4171	sn10callu
75%	short term	43	CO	15.0266	2.8602	0.0010	0.2596	41.148	2.1168	41.148	0.4171	sa75call
75%	short term	94	CO	13.9598	2.6208	0.0010	0.2596	41.148	2.1168	41.148	0.4171	ss75call
50%	short term	43	CO	12.3444	2.3310	0.0010	0.2596	41.148	2.1168	41.148	0.4171	sa50call
50%	short term	94	CO	11.7348	2.2176	0.0010	0.2596	41.148	2.1168	41.148	0.4171	ss50call
25%	short term	43	CO	9.8450	1.9026	0.0010	0.2596	41.148	2.1168	41.148	0.4171	sa25call
25%	short term	94	CO	9.4793	1.8018	0.0010	0.2596	41.148	2.1168	41.148	0.4171	ss25call
cold start-up	short term	43	CO	13.2893	31.3136	0.0010	0.2596	41.148	2.1168	41.148	0.4171	scSTcall
warm start-up	short term	43	CO	11.3690	42.4741	0.0010	0.2596	41.148	2.1168	41.148	0.4171	swSTcall
hot start-up	short term	43	CO	11.5519	41.5913	0.0010	0.2596	41.148	2.1168	41.148	0.4171	shSTcall

Table 11. Modeled emission rates used in AERMOD

CT/HRSG Load condition	AERMOD averaging period	Temp. (F)	Pollutant	CT/HRSG		Air Inlet Heater		Emergency Diesel Generator		Fire Water Pump		AERMOD input files (*.adi)
				exit velocity	emission rate	exit velocity	emission rate	exit velocity	emission rate	exit velocity	emission rate	
				m/s	g/s	m/s	g/s	m/s	g/s	m/s	g/s	
100% load + duct firing	annual	43	PM	19.0805	2.8854	0.0010	0.0004	41.148	0.0021	41.148	0.0004	aa10pxx
100% load + duct firing	short-term	43	PM	19.0805	2.8854	0.0010	0.0239	41.148	0.0102	41.148	0.0020	sa10pall
100% load + duct firing	short term	94	PM	17.8918	2.9232	0.0010	0.0239	41.148	0.0102	41.148	0.0020	ss10pall
100% load + duct firing	short term	-41	PM	21.1531	2.8098	0.0010	0.0239	41.148	0.0102	41.148	0.0020	sn10pall
100%, no duct firing	annual	43	PM	18.8671	2.1042	0.0010	0.0004	41.148	0.0021	41.148	0.0004	aa10pxxu
100%, no duct firing	short-term	43	PM	18.8671	2.1042	0.0010	0.0239	41.148	0.0102	41.148	0.0020	sa10pallu
100%, no duct firing	short term	94	PM	17.6174	1.9782	0.0010	0.0239	41.148	0.0102	41.148	0.0020	ss10pallu
100%, no duct firing	short term	-41	PM	21.0312	2.3436	0.0010	0.0239	41.148	0.0102	41.148	0.0020	sn10pallu
75%	annual	43	PM	15.0266	1.7136	0.0010	0.0004	41.148	0.0021	41.148	0.0004	aa75pxx
75%	short term	43	PM	15.0266	1.7136	0.0010	0.0239	41.148	0.0102	41.148	0.0020	sa75pall
75%	short term	94	PM	13.9598	1.5372	0.0010	0.0239	41.148	0.0102	41.148	0.0020	ss75pall
50%	annual	43	PM	12.3444	1.3734	0.0010	0.0004	41.148	0.0021	41.148	0.0004	aa50pxx
50%	short term	43	PM	12.3444	1.3734	0.0010	0.0239	41.148	0.0102	41.148	0.0020	sa50pall
50%	short term	94	PM	11.7348	1.2348	0.0010	0.0239	41.148	0.0102	41.148	0.0020	ss50pall
25%	annual	43	PM	9.8450	0.9450	0.0010	0.0004	41.148	0.0021	41.148	0.0004	aa25pxx
25%	short term	43	PM	9.8450	0.9450	0.0010	0.0239	41.148	0.0102	41.148	0.0020	sa25pall
25%	short term	94	PM	9.4793	0.8694	0.0010	0.0239	41.148	0.0102	41.148	0.0020	ss25pall
cold start-up	annual	43	PM	13.2893	0.3095	0.0010	0.0004	41.148	0.0021	41.148	0.0004	acSTpxx
cold start-up	short term	43	PM	13.2893	0.3095	0.0010	0.0239	41.148	0.0102	41.148	0.0020	scSTpall
warm start-up	annual	43	PM	11.3690	0.2515	0.0010	0.0004	41.148	0.0021	41.148	0.0004	awSTpxx
warm start-up	short-term	43	PM	11.3690	0.2515	0.0010	0.0239	41.148	0.0102	41.148	0.0020	swSTpall
hot start-up	annual	43	PM	11.5519	0.2352	0.0010	0.0004	41.148	0.0021	41.148	0.0004	ahSTpxx
hot start-up	short term	43	PM	11.5519	0.2352	0.0010	0.0239	41.148	0.0102	41.148	0.0020	shSTpall

Table 12. Results from AERMOD NO_x significant impacts analysis

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum annual (2000) concentration (μg/m^3)	Location of maximum concentration (eastings/northings)		Maximum annual (2001) concentration (μg /m^3)	Location of maximum concentration (eastings/northings)		AERMOD (*.adi) input files (xx=year)
100% load + duct firing	annual	43	NOX	*0.7078*	696247.69	4918666.00	*0.5458*	696247.69	4918666.00	aa10nxx
100%	annual	43	NOX	*0.7057*	696247.69	4918666.00	*0.5438*	696247.69	4918666.00	aa10nxxu
75%	annual	43	NOX	*0.7077*	696247.69	4918666.00	*0.5461*	696247.69	4918666.00	aa75nxx
50%	annual	43	NOX	*0.7092*	696247.69	4918666.00	*0.5490*	696247.69	4918666.00	aa50nxx
25%	annual	43	NOX	***0.7104***	696247.69	4918666.00	*0.5505*	696247.69	4918666.00	aa25nxx

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum annual (2002) concentration (μg /m^3)	Location of maximum concentration (eastings/northings)		Maximum annual (2003) concentration (μg /m^3)	Location of maximum concentration (eastings/northings)		AERMOD (*.adi) input files (xx=year)
100% load + duct firing	annual	43	NOX	*0.5215*	696247.69	4918666.00	*0.6495*	696247.69	4918666.00	aa10nxx
100%	annual	43	NOX	*0.5196*	696247.69	4918666.00	*0.6479*	696247.69	4918666.00	aa10nxxu
75%	annual	43	NOX	*0.5205*	696247.69	4918666.00	*0.6491*	696247.69	4918666.00	aa75nxx
50%	annual	43	NOX	*0.5221*	696247.69	4918666.00	*0.6502*	696247.69	4918666.00	aa50nxx
25%	annual	43	NOX	*0.5236*	696247.69	4918666.00	*0.6509*	696247.69	4918666.00	aa25nxx

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum annual (2004) concentration (μg /m^3)	Location of maximum concentration (eastings/northings)		AERMOD (*.adi) input files (xx=year)
100% load + duct firing	annual	43	NOX	*0.6592*	696247.69	4918666.00	aa10nxx
100%	annual	43	NOX	*0.6572*	696247.69	4918666.00	aa10nxxu
75%	annual	43	NOX	*0.6580*	696247.69	4918666.00	aa75nxx
50%	annual	43	NOX	*0.6588*	696247.69	4918666.00	aa50nxx
25%	annual	43	NOX	*0.6596*	696247.69	4918666.00	aa25nxx

Table 13. Results from AERMOD CO significant impacts analysis

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum 8-hr average concentration (μg /m^3)	Location of maximum concentration (eastings/northings)		Maximum 1-hr average concentration (μg /m^3)	Location of maximum concentration (eastings/northings)		AERMOD (*.adi) input files (xx=year)
100% load + duct firing	short term	43	CO	*236.2875*	696339.81	4918819.00	***518.4735***	696584.88	4918830.00	sa10call
100% load + duct firing	short term	94	CO	*236.2875*	696339.81	4918819.00	*518.4734*	696584.88	4918830.00	ss10call
100% load + duct firing	short term	-41	CO	*236.2875*	696339.81	4918819.00	*518.4735*	696584.88	4918830.00	sn10call
100%, no duct firing	short term	43	CO	*236.2875*	696339.81	4918819.00	*518.4733*	696584.88	4918830.00	sa10callu
100%, no duct firing	short term	94	CO	*236.2875*	696339.81	4918819.00	*518.4733*	696584.88	4918830.00	ss10callu
100%, no duct firing	short term	-41	CO	*236.2875*	696339.81	4918819.00	*518.4733*	696584.88	4918830.00	sn10callu
75%	short term	43	CO	*236.2875*	696339.81	4918819.00	*518.4732*	696584.88	4918830.00	sa75call
75%	short term	94	CO	*236.2875*	696339.81	4918819.00	*518.4732*	696584.88	4918830.00	ss75call
50%	short term	43	CO	*236.2875*	696339.81	4918819.00	*518.4731*	696584.88	4918830.00	sa50call
50%	short term	94	CO	*236.2875*	696339.81	4918819.00	*518.4731*	696584.88	4918830.00	ss50call
25%	short term	43	CO	*236.2875*	696339.81	4918819.00	*518.4731*	696584.88	4918830.00	sa25call
25%	short term	94	CO	*236.2875*	696339.81	4918819.00	*518.4731*	696584.88	4918830.00	ss25call
cold start-up	short term	43	CO	*236.2875*	696339.81	4918819.00	*518.4731*	696584.88	4918830.00	scSTcall
warm start-up	short term	43	CO	*236.2875*	696339.81	4918819.00	*518.4731*	696584.88	4918830.00	swSTcall
hot start-up	short term	43	CO	*236.2875*	696339.81	4918819.00	*518.4731*	696584.88	4918830.00	shSTcall

Table 14. Results from AERMOD PM significant impacts analysis

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum average concentration ($\mu g/m^3$)	Location of maximum concentration (eastings/northings)		AERMOD (*.adi) input files (xx=year)
100% load + duct firing	24-hr	43	PM	*3.56632*	696339.81	4918819.00	sa10pall
100% load + duct firing	24-hr	94	PM	*3.56648*	696339.81	4918819.00	ss10pall
100% load + duct firing	24-hr	-41	PM	*3.56609*	696339.81	4918819.00	sn10pall
100%	24-hr	43	PM	*3.56581*	696339.81	4918819.00	sa10pallu
100%	24-hr	94	PM	*3.56582*	696339.81	4918819.00	ss10pallu
100%	24-hr	-41	PM	*3.56581*	696339.81	4918819.00	sn10pallu
75%	24-hr	43	PM	*3.56588*	696339.81	4918819.00	sa75pall
75%	24-hr	94	PM	*3.56585*	696339.81	4918819.00	ss75pall
50%	24-hr	43	PM	***3.57049***	696339.81	4918819.00	sa50pall
50%	24-hr	94	PM	*3.56958*	696339.81	4918819.00	ss50pall
25%	24-hr	43	PM	*3.56962*	696339.81	4918819.00	sa25pall
25%	24-hr	94	PM	*3.56929*	696339.81	4918819.00	ss25pall
cold start-up	24-hr	43	PM	*3.56524*	696339.81	4918819.00	scSTpall
warm start-up	24-hr	43	PM	*3.56575*	696339.81	4918819.00	swSTpall
hot start-up	24-hr	43	PM	*3.56559*	696339.81	4918819.00	shSTpall

Table 15. Results from AERMOD PM significant impacts analysis

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum annual (2000) concentration ($\mu g/m^3$)	Location of max. concentration (eastings/northings)		Maximum annual (2001) concentration ($\mu g/m^3$)	Location of max. concentration (eastings/northings)		AERMOD (*.adi) input files (xx=year)
100% load + duct firing	annual	43	PM	*0.0938*	696269.31	4919178.00	*0.0953*	696319.31	4919178.00	aa10pxx
100%	annual	43	PM	*0.0709*	696269.31	4919178.00	*0.0723*	696319.31	4919128.00	aa10pxxu
75%	annual	43	PM	*0.0794*	696319.31	4919128.00	*0.0791*	696319.31	4919128.00	aa75pxx
50%	annual	43	PM	*0.0802*	696269.31	4919128.00	*0.0821*	696319.31	4919128.00	aa50pxx
25%	annual	43	PM	*0.0723*	696269.31	4919078.00	*0.0734*	696369.31	4919078.00	aa25pxx

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum annual (2002) concentration ($\mu g/m^3$)	Location of max. concentration (eastings/northings)		Maximum annual (2003) concentration ($\mu g/m^3$)	Location of max. concentration (eastings/northings)		AERMOD (*.adi) input files (xx=year)
100% load + duct firing	annual	43	PM	*0.1032*	696319.31	4919128.00	***0.1224***	696219.31	4919228.00	aa10pxx
100%	annual	43	PM	*0.0779*	696319.31	4919128.00	*0.0919*	696219.31	4919228.00	aa10pxxu
75%	annual	43	PM	*0.0845*	696319.31	4919128.00	*0.0992*	696269.31	4919128.00	aa75pxx
50%	annual	43	PM	*0.0850*	696319.31	4919128.00	*0.1013*	696269.31	4919128.00	aa50pxx
25%	annual	43	PM	*0.0755*	696319.31	4919128.00	*0.0903*	696269.31	4919078.00	aa25pxx

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum annual (2004) concentration ($\mu g/m^3$)	Location of max. concentration (eastings/northings)		AERMOD (*.adi) input files (xx=year)
100% load + duct firing	annual	43	PM	*0.0988*	696269.31	4919178.00	aa10pxx
100%	annual	43	PM	*0.0747*	696269.31	4919178.00	aa10pxxu
75%	annual	43	PM	*0.0821*	696269.31	4919128.00	aa75pxx
50%	annual	43	PM	*0.0833*	696269.31	4919128.00	aa50pxx

25%	annual	43	PM	*0.0744*	696269.31	4919078.00	aa25pxx

Table 16. Results from AERMOD PM significant impacts analysis (annual averaging period)

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum (2000) concentration (ug/m^3)	Location of max. concentration (eastings/northings)		Maximum (2001) concentration (ug/m^3)	Location of max. concentration (eastings/northings)		AERMOD (*.adi) file name (xx=year)
cold start-up	annual	43	PM	*0.0270*	696247.69	4918666.00	*0.0240*	696339.81	4918819.00	acSTpxx
warm start-up	annual	43	PM	*0.0272*	696247.69	4918666.00	*0.0241*	696339.81	4918819.00	awSTpxx
hot start-up	annual	43	PM	*0.0271*	696247.69	4918666.00	*0.0239*	696339.81	4918819.00	ahSTpxx

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum (2002) concentration (ug/m^3)	Location of max. concentration (eastings/northings)		Maximum (2003) concentration (ug/m^3)	Location of max. concentration (eastings/northings)		AERMOD (*.adi) file name (xx=year)
cold start-up	annual	43	PM	*0.0237*	696269.31	4919028.00	***0.0277***	696269.31	4919028.00	acSTpxx
warm start-up	annual	43	PM	*0.0237*	696319.31	4918978.00	*0.0276*	696269.31	4919028.00	awSTpxx
hot start-up	annual	43	PM	*0.0226*	696319.31	4918978.00	*0.0261*	696269.31	4919028.00	ahSTpxx

Load Condition	Averaging Period	Temperature (F)	Pollutant	Maximum (2004) concentration (ug/m^3)	Location of max. concentration (eastings/northings)		AERMOD (*.adi) file name (xx=year)
cold start-up	annual	43	PM	*0.0249*	696247.69	4918666.00	acSTpxx
warm start-up	annual	43	PM	*0.0250*	696247.69	4918666.00	awSTpxx
hot start-up	annual	43	PM	*0.0249*	696247.69	4918666.00	ahSTpxx

Table 17. Comparison of maximum modeled impacts with modeling significance levels and De minimus monitoring exemption levels

Pollutant	Averaging period	Maximum modeled impact ($\mu g/m^3$) (from Table 12-Table 16)	Modeling significance levels (MSL) ($\mu g/m^3$) (from Table 4)	Maximum modeled impact (% MSL)	De minimus monitoring exemption ($\mu g/m^3$)	Maximum modeled impact (% De minimus concentration)
CO	1-hour	518.4735	2,000	25.92%		
	8-hour	236.2875	500	47.26%	575	41.09%
NO_x	Annual	0.7104	1	71.04%	14	5.07%
PM_{10}	24-hr	3.5705	5	71.41%	10	35.70%
	Annual	0.1224	1	12.24%		

Table 18. Comparison of maximum modeled PM concentrations with $PM_{2.5}$ NAAQS

Pollutant	Averaging period	Maximum modeled impact ($\mu g/m^3$)	Background concentration ($\mu g/m^3$) (Note 2)	Maximum total impact ($\mu g/m^3$)	PM 2.5 NAAQS ($\mu g/m^3$)	Maximum modeled impact as (% of PM 2.5 NAAQS)
$PM_{2.5}$	24-hr	3.5705 (Note 3)	23	26.6	35	75.92%
	Annual	0.1224 (Note 4)	9.7	9.8	15	65.48%

[2] These background concentrations were recorded by monitor #46-011-0002 at the City Hall in Brookings, SD. The 24-hour background value is the 98th percentile reading listed in DENR (2007; Table 6.1). The annual value is the maximum recorded annual value in DENR (2007; Figure 6-3).
[3] Maximum modeled 24-hour average concentration during 2000-2004.
[4] Maximum modeled annual concentration during 2000-2004.

Table 19. AERMOD system input and output files

Scenario description	Pollutant	Averaging Period	Input/ output files (*.adi/.out) (xx=00, 01, 02, 03, 04)	7.5 min. Digital Elevation Map (DEM) and other files
100% load + duct firing	NOX	annual	aa10nxx	Astoria
100%	NOX	annual	aa10nxxu	Aurora
75%	NOX	annual	aa75nxx	Arco
50%	NOX	annual	aa50nxx	Brookings
25%	NOX	annual	aa25nxx	Brookings NE
100% load + duct firing	CO	short-term	sa10call	Canby SE
100% load + duct firing	CO	short-term	ss10call	Elkton
100% load + duct firing	CO	short-term	sn10call	Estelline SE
100%, no duct firing	CO	short-term	sa10callu	Flandreau NE
100%, no duct firing	CO	short-term	ss10callu	Flandreau NW
100%, no duct firing	CO	short-term	sn10callu	Hendricks
75%	CO	short-term	sa75call	Lake Benton NE
75%	CO	short-term	ss75call	Lake Benton NW
50%	CO	short-term	sa50call	Lake Benton SW
50%	CO	short-term	ss50call	Lake Benton
25%	CO	short-term	sa25call	Medary
25%	CO	short-term	ss25call	Porter SW
cold start-up	CO	short-term	scSTcall	Ruthton NW
warm start-up	CO	short-term	swSTcall	Toronto
hot start-up	CO	short-term	shSTcall	Tyler
100% load + duct firing	PM	annual	aa10pxx	Verdi
100% load + duct firing	PM	short-term	sa10pall	White NE
100% load + duct firing	PM	short-term	ss10pall	White SE
100% load + duct firing	PM	short-term	sn10pall	White
100%, no duct firing	PM	annual	aa10pxxu	
100%, no duct firing	PM	short-term	sa10pallu	
100%, no duct firing	PM	short-term	ss10pallu	
100%, no duct firing	PM	short-term	sn10pallu	
75%	PM	annual	aa75pxx	
75%	PM	short-term	sa75pall	
75%	PM	short-term	ss75pall	
50%	PM	annual	aa50pxx	
50%	PM	short-term	sa50pall	
50%	PM	short-term	ss50pall	

Table 19. AERMOD system input and output files

Scenario description	Pollutant	Averaging Period	Input/ output files (*.adi/.out) (xx=00, 01, 02, 03, 04)	7.5 min. Digital Elevation Map (DEM) and other files
25%	PM	annual	aa25pxx	**Meteorological input data**
25%	PM	short-term	sa25pall	HON_ABR.SFC
25%	PM	short-term	ss25pall	HON_ABR.PFL
cold start-up	PM	annual	acSTpxx	
cold start-up	PM	short-term	scSTpall	
warm start-up	PM	annual	awSTpxx	
warm start-up	PM	short-term	swSTpall	**BPIP files**
hot start-up	PM	annual	ahSTpxx	Deer_Creek.bpi
hot start-up	PM	short-term	shSTpall	Deer_Creek.pro