Statement of Basis

Prevention of Significant Deterioration Air Quality Preconstruction Permit

Deer Creek Station

Near White

Brookings County, South Dakota

South Dakota Department of Environment and Natural Resources

Table of Contents

Page

1.0 Background 1

2.0 Operational Description 1
- 2.1 Combustion Turbine/Heat Recovery Steam Generator 1
- 2.2 Air-Cooled Condenser 2
- 2.3 Emergency Generator and Fire Water Pump 2
- 2.4 Air Inlet Heater 2
- 2.5 Process Equipment 3

4.0 New Source Performance Standards 5
- 4.1 ARSD 74:36:07:01 – 40 CFR Part 60, Subpart A 5
- 4.2 ARSD 74:36:07:14 – 40 CFR Part 60, Subpart Kb 5
- 4.3 ARSD 74:36:07:18 – 40 CFR Part 60, Subpart GG 5
- 4.4 ARSD 74:36:07:88 – 40 CFR Part 60, Subpart IIII 6
- 4.5 ARSD 74:36:07:89 – 40 CFR Part 60, Subpart KKKK 8
- 4.6 Review of Other Regulations in 40 CFR Part 60 9

5.0 National Emission Standards for Hazardous Air Pollutants 9
- 5.1 ARSD 74:36:08:39 – 40 CFR Part 63, Subpart YYYY 9
- 5.2 ARSD 74:36:08:40 – 40 CFR Part 63, Subpart ZZZZ 10
- 5.3 Review of Other Regulations in 40 CFR Part 63 11

6.0 New Source Review 11

7.0 Prevention of Significant Deterioration 11
- 7.1 Best Available Control Technology (BACT) Analysis 13
- 7.2 Combustion Turbine/Heat Recovery Steam Generator BACT Analysis 16
  - 7.2.1 Nitrogen Oxide BACT for Combustion Turbine/Heat Recovery Steam Generator 16
  - 7.2.2 Carbon Monoxide BACT for Combustion Turbine 21
  - 7.2.3 Particulate Matter BACT for Combustion Turbine 26
- 7.3 Emergency Generator and Fire Water Pump BACT Analysis 28
  - 7.3.1 Combustion Controls 29
  - 7.3.2 Post-Combustion Emission Control Technologies 29
    - 7.3.2.1 NO_x Absorption Systems 30
    - 7.3.2.2 Catalytic Reduction Systems 30
    - 7.3.2.3 Particulate Control Systems 31
- 7.4 Inlet Air Heater BACT Analysis 33
- 7.5 Air Quality Analysis 34
  - 7.5.1 Significant Impact Levels (SILs) and De minimis Monitoring Levels 35
  - 7.5.2 New 1-hour NAAQS for Nitrogen Dioxide 36
  - 7.5.3 Other Impacts 37
    - 7.5.3.1 Commercial, Residential, and Industrial Growth 37
    - 7.5.3.2 Ambient Air Quality Impacts 37

Table of Contents

Page

7.5.3.3 Soils and Vegetation 38
7.5.3.4 Class I Area Impacts 38
7.5.3.5 Plume Visibility 38
7.6 Operational Restrictions 41
7.7 Compliance Demonstration 41

8.0 Acid Rain Program 42

9.0 State Requirements 42

10.0 Recommendation 43

1.0 Background

On June 1, 2009, the South Dakota Department of Environment and Natural Resources (DENR) received an application from Basin Electric Power Cooperative (BEPC) for a Prevention of Significant Deterioration (PSD) preconstruction permit to construct a natural gas-fired combined cycle power generating facility in Brookings County near White, South Dakota. The new facility, to be known as the Deer Creek generating station, will consist of a natural gas-fired combustion turbine and a heat recovery steam generator capable of providing approximately 300 megawatts of electricity. The primary standard industrial classification code for the facility is 4911 – Electric, Gas, and Sanitary Services – Electric Services. DENR requested additional information from BEPC on August 3, 2009. The application was considered complete on August 28, 2009.

2.0 Operational Description

The major components of the facility include the combustion turbine, heat recovery steam generator, 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 inlet air heater.

The natural gas-fired combustion turbine and heat recovery steam generator will generate a nominal 300 megawatts of electricity. The Deer Creek generating station will include the following equipment:

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

2.1 Combustion Turbine/Heat Recovery Steam Generator

The Deer Creek generating station includes one F-class (or equivalent) natural gas-fired combustion turbine and heat recovery steam generator. The proposed combustion turbine 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 combustion turbine and compressed in a multiple-stage axial flow compressor. Compressed air and natural gas are mixed and combusted in the combustion turbine's combustion chamber. 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. The combustion turbine is designed to produce a nominal 166 megawatts of gross electrical power at full load and an average annual ambient temperature of 43°F.

Hot exhaust gas from the combustion turbine is directed to the heat recovery steam generator where excess heat is used to generate steam. The heat recovery steam generator 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 heat recovery steam generator is used to drive a single steam turbine connected to an electrical generator with a nominal power output of 143 megawatts with duct firing and 84 megawatts without duct firing at an average annual ambient temperature of 43°F.

2.2 Air-Cooled Condenser

Steam from the low pressure section of the steam turbine will be condensed in an air-cooled condenser prior to being recycled. In an air-cooled condenser, steam discharged from the turbine 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 used as the cooling medium and cools the steam without coming into contact with the condensate or any other potential contaminants, no air emissions are associated with an air-cooled condensing system. Therefore, the air-cooled condenser is not a source of air emissions for the Deer Creek generating station.

2.3 Emergency Generator and Fire Water Pump

The Deer Creek generating station will have an emergency diesel generator and fire water pump. The emergency diesel generator will supply power to the essential service motor control center during an interruption of the electrical power supply to the facility, including building heat and fuel supply systems, plant communication systems, and essential emergency lighting. The emergency diesel generator will be designed to provide 2,000 kilowatts of power during emergency situations and the fire water pump will be designed at 577 horsepower to provide a water flow rate of 3,000 gallons per minute. Both engines will be designed to fire ultra low-sulfur diesel fuel. The engines will be used only in case of emergency and for periodic testing to ensure that the units will be operational in an emergency.

2.4 Air Inlet Heater

The Deer Creek generating station will have one natural gas-fired inlet heater to preheat the combustion turbine 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 through a heat exchanger on the combustion turbine air intake. The heater will operate for approximately 10 to 20 minutes. After the combustion turbine is up to speed, the inlet air heater will shut off and bleed heat from the compressor will be used to heat the combustion turbine inlet air. The air inlet heater will have a maximum design inlet heat input of 25.0 million Btu per hour to provide a heat duty of 19.0 million Btus per hour. The unit will fire pipeline natural gas.

2.5 Process Equipment

Table 2-1 lists the equipment and emissions sources identified in the permit application for the proposed facility that will be reviewed for coverage under the permit.

Table 2-1 – Process Equipment

Unit	Description	Operating Rate [1]	Control Device
#1	Combustion turbine/heat recovery steam generator, F-class (or equivalent), fired with natural gas.	Combustion turbine – 1,713 MMBtus per hour (Lower Heating Value) heat input.	Low-NOx burners and selective catalytic reduction.
		Duct burners – 615.2 MMBtus per hour (Lower Heating Value) heat input.	
#2	Emergency generator fueled with ultra low sulfur distillate oil.	2,000 kilowatts.	Not applicable
#3	Fire water pump fueled with ultra low sulfur distillate oil.	577 horsepower.	Not applicable
#4	Inlet air heater fueled with natural gas.	25.0 MMBtus per hour heat input.	Not applicable

[1] – The operating rate is the nominal or manufacturer provided operating rate given in the PSD application and are descriptive only.

3.0 Potential Emissions

Emissions from the Deer Creek generating station will result from the combustion turbine/heat recovery steam generator, the emergency diesel generator, emergency fire water pump, and the air inlet heater. Emissions from the combustion turbine/heat recovery steam generator are a combination of combustion turbine emissions, duct burner emissions, and emissions associated with unit startup. BEPC calculated the potential annual emissions from the combustion turbine/heat recovery steam generator based on the following assumptions:

- 708 hours per year in startup mode;
- 2,200 hours per year at 41°F with 100% load and maximum duct burner firing; and
- 5,852 hours per year at 41°F with 100% load and no duct firing.

These assumptions are considered to provide a conservative estimate of potential emissions because the Deer Creek generating station will probably never operate continuously at full load for an entire year. Also, duct burner firing will likely occur during the summer at temperatures greater than 41°F, which will result in lower mass emission rates. The potential controlled emissions for nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4) for the combustion turbine/heat recovery steam generator are summarized in Table 3-1.

Table 3-1 – Combustion Turbine/Heat Recovery Steam Generator Potential Emissions

Operating Mode	NO_x [2]	CO [2]	VOC [2]	PM (filterable)	PM (total)	SO_2	H_2SO_4
	(tpy) [3]	(tpy) [3]	(tpy) [3]	(tpy) [3]	(tpy) [3]	(tpy) [3]	(tpy) [3]
Full Load without Duct Firing	63.8	83.4	8.0	26.6	54.8	8.0	1.5
Full Load with Duct Firing	32.1	62.9	15.5	12.0	25.2	3.6	0.7
Startup Emissions [1]	20.7	108.0	6.1	--	--	--	--
Total Emissions	**116.6**	**245.3**	**29.6**	**38.6**	**80.0**	**11.6**	**2.2**

[1] – According to BEPC's application, emissions of particulate matter (PM), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4) are not expected to change appreciably during startup. Therefore, total annual emissions for these pollutants were calculated assuming 2,200 hours/year duct firing and 6,560 hours/year at full load without duct firing. Emissions of other PSD pollutants, including fluorides and lead, are expected to be negligible;
[2] – "NOx" means nitrogen oxide, "CO" means carbon monoxide, and "VOC" means volatile organic compound; and
[3] – "tpy" means tons per year.

Based on preliminary design calculations, the emergency diesel generator will be designed to provide 2,000 kilowatts of power during emergency situations, and the fire water pump will be designed at 577 horsepower to provide a water flow rate of 3,000 gallons per minute. The proposed designs are conservative and the installed units may have smaller capacities. The inlet air heater will be used to preheat the combustion turbine intake air under conditions of extreme cold (approximately -25°F). The heater will be designed based on a maximum heat input of 25 MMBtus per hour to provide a heat duty of 19.0 MMBtus. BEPC calculated the potential emissions for all three units based on limiting the hours of operation to 150 hours per year. The potential annual controlled emissions for nitrogen oxides (NOx), carbon monoxide, volatile organic compounds, particulate matter, sulfur dioxide, and sulfuric acid mist from the proposed operation of the Deer Creek generating station are summarized in Table 3-2.

Table 3-2 – Deer Creek Generating Station – Total Annual Potential Controlled Emissions

Unit	NO_x	CO	VOC	PM (filterable)	PM (total)	SO_2	H_2SO_4	Lead
	(tpy)[2]	(tpy)[2]	(tpy)[2]	(tpy)[2]	(tpy)[2]	(tpy)[2]	(tpy)[2]	(tpy)[2]
CT/HRSG [1]	116.6	254.3	29.6	38.6	80.0	11.6	2.2	3.59×10^{-4}
Emergency Diesel Generator	2.2	1.3	0.14	0.07	0.07	0.09	0.007	Negligible
Fire water Pump	0.18	0.25	0.11	0.014	0.014	0.02	0.001	Negligible
Inlet Air Heater	0.09	0.15	0.010	0.004	0.014	0.002	7.5×10^{-5}	9.38×10^{-7}
Total Emissions	**119**	**256**	**30**	**39**	**80**	**12**	**2**	**0**

[1] – "CT/HRSG" means combustion turbine/heat recovery steam generator; and
[2] – "tpy" means tons per year.

4.0 New Source Performance Standards

DENR reviewed the new source performance standards (NSPS) under 40 CFR Part 60 and determined that the following may be applicable to the Deer Creek generating station.

4.1 ARSD 74:36:07:01 – 40 CFR Part 60, Subpart A

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 items: (1) notification of the date construction is commenced; (2) notification of the actual date of initial startup; (3) initial performance tests; (4) notification of any performance test dates; (5) general monitoring requirements; and (6) general recordkeeping requirements. If the Deer Creek generating station is subject to a source-specific NSPS, the general provisions in subpart A are applicable.

4.2 ARSD 74:36:07:14 – 40 CFR Part 60, Subpart Kb

Subpart Kb is applicable to facilities which have a storage vessel with a capacity greater than or equal to 75 cubic meters that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. In accordance with 40 CFR § 60.110b(b), this rule does not apply to storage vessels with a capacity greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

There will be two distillate oil fuel storage tanks located at the Deer Creek generating station. The emergency diesel generator fuel tank will have a capacity of 3,000 gallons (11.4 cubic meters) and the emergency fire water pump fuel tank will have a capacity of 700 gallons (2.6 cubic meters). The fuel storage tanks are not subject to the provisions of this subpart because they are smaller than 75 cubic meters.

4.3 ARSD 74:36:07:18 – 40 CFR Part 60, Subpart GG

The EPA originally promulgated standards of performance for stationary gas turbines on September 10, 1979. The provisions of this subpart were applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigaJoules (10 million Btus) per hour, based on the lower heating value of the fuel fired, that commenced construction, modification, or reconstruction after October 3, 1977.

On July 6, 2006, EPA promulgated standards of performance for new stationary gas turbines. Subpart KKKK contains emission standards and compliance schedules for the control of emissions from stationary combustion turbines. Subpart KKKK is applicable to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigaJoules (10 MMBtus) per hour that commenced construction, modification, or reconstruction after February 18, 2005. Stationary combustion turbines that are subject to Subpart KKKK are exempt from Subpart GG. The Deer Creek generating station is subject to 40 CFR Part 60, Subpart KKKK. Therefore, the Deer Creek combustion turbine is exempt from the provisions of this subpart.

4.4 ARSD 74:36:07:88 – 40 CFR Part 60, Subpart IIII

On July 11, 2006, EPA promulgated new source performance standards for stationary compression ignition (CI) internal combustion engines (ICE). The compression ignition internal combustion engines new source performance standard limits emissions of nitrogen oxide, particulate matter, sulfur dioxide, carbon monoxide, and hydrocarbons from stationary diesel internal combustion engines. The provisions of this subpart are applicable to owners and operators of stationary compression ignition internal combustion engines that commence construction after July 11, 2005, where the stationary compression ignition internal combustion engines are:

- Manufactured after April 1, 2006 and are not fire pump engines, or
- Manufactured as a certified National Fire Protection Association fire pump engine after July 1, 2006.

For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

In accordance with 40 CFR § 60.4219, a compression ignition means a type of stationary internal combustion engine that is not a spark ignition engine. A spark ignition engine is an engine that uses gasoline, natural gas or liquefied petroleum. Compression ignition engines include internal combustion engines that are not spark ignition engines, including diesel engines. Both the emergency diesel generator and the fire water pump proposed for the Deer Creek generating station are classified as stationary compression ignition engines subject to the provisions of this subpart. Emissions standards under this subpart depend on the horsepower class and mode of operation (i.e., continuous or emergency) of the engine. The emergency diesel generator and fire water pump are both classified as emergency stationary internal combustion engines, and the fire water pump meets the definition of a fire pump engine.

The standard includes emission standards for model year 2007 and later emergency stationary compression ignition internal combustion engines with a maximum engine power less than or equal to 2,237 kilowatts (3,000 horsepower) and a displacement of less than 10 liters per cylinder that are not fire pump engines. The emergency diesel generator engine proposed for the Deer Creek generating station falls into this engine classification. The rule requires that emergency stationary compression ignition internal combustion engines meet the Tier 2 through Tier 3 nonroad compression ignition engine emission standards, and Tier 4 nonroad compression ignition 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.

In accordance with 40 CFR § 60.4205(b), owners and operators of 2007 model year and later emergency stationary compression ignition internal combustion engines with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad compression ignition engines in 40 CFR § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary compression ignition internal combustion engines. In accordance with 40 CFR § 60.4202(a)(2), stationary compression ignition internal combustion engine manufacturers

must certify their 2007 model year and later emergency stationary compression ignition internal combustion engines with a maximum engine power greater than or equal to 37 kilowatts (50 horsepower) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad compression ignition engines for the same model year and maximum engine power in 40 CFR § 89.112 and 40 CFR § 89.113 for all pollutants beginning in model year 2007. The applicable emission standards from Table 1 in 40 CFR § 89.112 are given in Table 4-1 and are based on the rated power of the generator and the model year. The model years listed in the table indicate the model years for which the specified tier of standards take effect.

Table 4-1 – NSPS Emission Standards – Emergency Diesel Generator

Rated Power (kW)	Tier	Model Year [1]	NO_x [2]	HC [3]	NMHC and NOx [4]	CO [5]	PM [6]
			grams/kilowatt-hour				
kW>560	**Tier 1**	**2000**	9.2	1.3	--	11.4	0.54
	Tier 2	**2006**	--	--	6.4	3.5	0.2

[1] – The model years listed indicated the model years for which the specified tier of standards take effect;
[2] – NO_x = Nitrogen Oxides;
[3] – HC = Hydrocarbon;
[4] – NMHC and NOx = Nonmethane Hydrocarbons and Nitrogen Oxides;
[5] – CO = Carbon Monoxide; and
[6] – PM = Particulate Matter.

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 engine horsepower. In accordance with 40 CFR § 60.4205(c), owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in Table 4 of Subpart IIII, for all pollutants. The proposed Deer Creek generating station will have a 577 horsepower emergency fire water pump. The applicable emission standards for new stationary fire pump engines with an engine horsepower greater than or equal to 300 horsepower and less than 600 horsepower are given in Table 4-2.

Table 4-2 – NSPS Emission Standards – Stationary Fire Water Pump Engine

Maximum Engine Power	Model Year(s)	NMHC and NOx [1] g/KW-hr [4] (g/HP-hr) [5]	CO [2] g/KW-hr [4] (g/HP-hr) [5]	PM [3] g/KW-hr [4] (g/HP-hr) [5]
225 ≤ KW < 450	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
(300 ≤ HP < 600)	2009+ [6]	4.0 (3.0)	3.5 (2.6)	0.2 (0.15)

[1] – NMHC and NOx = Nonmethane Hydrocarbons and Nitrogen Oxides;
[2] – CO = Carbon Monoxide;
[3] – PM = Particulate Matter;
[4] – grams/kilowatt-hour;
[5] – grams/horsepower-hour; and
[6] – In model years 2009-2011, 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.

In accordance with 40 CFR § 60.4207(a), beginning on October 1, 2007, owners and operators of stationary compression ignition internal combustion engines subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR § 80.510(a). 40 CFR § 80.510(a) states that all non-road, locomotive, and marine diesel fuel is limited to 500 parts per million (ppm) maximum sulfur content (or 0.05%) and a minimum cetane index of 40, or a maximum aromatic content of 35 volume percent.

In accordance with 40 CFR § 60.4207(b), on October 1, 2010, owners and operators of stationary compression ignition internal combustion engines subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR § 80.510(b) for nonroad diesel fuel. 40 CFR § 80.510(b) states that all non-road diesel fuel is limited to a maximum sulfur content of 15 ppm (or 0.0015%) and a minimum cetane index of 40, or a maximum aromatic contact of 35 volume percent.

In accordance with 40 CFR § 60.4209(a), the owner or operator of an emergency stationary compression ignition internal combustion engine must install a non-resettable hour meter prior to startup of the engine.

In accordance with 40 CFR § 60.4211, the owner or operator of a stationary compression ignition internal combustion engine subject to the emission standards in this subpart must operate and maintain the stationary compression ignition internal combustion engine according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine. In addition, owners and operators may only change those settings that are permitted by the manufacturer.

According to the provisions in 40 CFR § 60.4211(e), emergency stationary internal combustion engines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing is limited to 100 hours per year. There is no time limit on the use of emergency stationary internal combustion engines in emergency situations. Any operation of the emergency generator other than emergency operation, and maintenance and testing as permitted, is prohibited.

The owner or operator of a compression ignition internal combustion engine or compression ignition fire pump engine must comply with the provisions of Subpart IIII by purchasing an engine certified to the applicable emission standards for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications. BEPC will be required to purchase engines certified by the manufacturer to meet the applicable emission standards.

4.5 ARSD 74:36:07:89 – 40 CFR Part 60, Subpart KKKK

EPA promulgated standards of performance for new stationary gas turbines on July 6, 2006. Subpart KKKK contains emission standards and compliance schedules for the control of emissions from stationary combustion turbines. The provisions of this subpart are applicable to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 giga

Joules (10 MMBtus) per hour that commenced construction, modification, or reconstruction after February 18, 2005.

A stationary combustion turbine means all equipment, including but not limited to the 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 combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Stationary combustion turbines subject to this subpart are exempt from the NSPS requirements of 40 CFR Part 60, subpart GG. Heat recovery steam generators and duct burners regulated under this subpart are exempt from the NSPS requirements of 40 CFR Part 60, subparts Da, Db, and Dc.

Subpart KKKK includes emission standards for nitrogen oxide and sulfur dioxide. The Deer Creek generating station's combustion turbine will have a heat input at peak load greater than 850 MMBtu per hour (Higher Heating Value). Therefore, in accordance with 40 CFR §60.4320, as referenced to Table 1, the combustion turbine must meet a nitrogen oxide emission limit of 15 parts per million at 15% oxygen or 54 nanograms per Joule of useful output (0.43 pounds per megawatt-hour). In accordance with 40 CFR §60.4330, the combustion turbine is subject to the following sulfur dioxide emission limits:

(1) The owner or operator shall not cause to be discharged into the atmosphere from the stationary combustion turbine any gases which contain sulfur dioxide in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or
(2) The owner or operator must not burn in the stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 nanograms of sulfur dioxide per Joule (0.060 pounds of sulfur dioxide per MMBtu) heat input.

4.6 Review of Other Regulations in 40 CFR Part 60

DENR reviewed the remaining sections in the new source performance standards and did not identify any other standards applicable to the Deer Creek generating station.

5.0 National Emission Standards for Hazardous Air Pollutants

DENR reviewed the Maximum Achievable Control Technology Standards (MACT) in 40 CFR Part 63 and determined that the following may be applicable.

5.1 ARSD 74:36:08:39 – 40 CFR Part 63, Subpart YYYY

The provisions of this subpart are applicable to owners or operators of a stationary combustion turbine located at a major source of hazardous air pollutant emissions. A stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and

exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion or any stationary combined cycle steam/electric generating system. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines.

A major source of hazardous air pollutant emissions is a plant site that emits or has the potential to emit any single hazardous air pollutant at a rate of 10 tons or more per year or any combination of hazardous air pollutant at a rate of 25 tons or more per year. An area source of hazardous air pollutant emissions is a source that is not a major source. Based on emission calculations submitted in the PSD application, potential hazardous air pollutant emissions from all sources at the proposed Deer Creek generating station are less than 25 tons per year. Formaldehyde, with potential emissions of 4.5 tons per year, is the individual hazardous air pollutant emitted in the largest quantity. Because the facility does not have the potential to emit 10 tons or more per year of any single hazardous air pollutant and/or 25 tons per year or more of a combination of hazardous air pollutants, the Deer Creek generating station does not meet the definition of a major source of hazardous air pollutant emissions. The Deer Creek generating station is an area source of hazardous air pollutants and not subject to Subpart YYYY.

5.2 ARSD 74:36:08:40 – 40 CFR Part 63, Subpart ZZZZ

The provisions of this subpart are applicable to owners or operators of a stationary reciprocating internal combustion engine (RICE) at a major or area source of HAP emissions. A stationary reciprocating internal combustion engine is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. At the Deer Creek generating station, the emergency generator (Unit #2) and fire pump engine (Unit #3) are considered reciprocating internal combustion engines. A major source of hazardous air pollutant (HAP) emissions is a plant site that emits or has the potential to emit any single hazardous air pollutant at a rate of 10 tons or more per year or any combination of hazardous air pollutants at a rate of 25 tons or more per year. An area source of hazardous air pollutant emissions is a source that is not a major source.

Based on emission calculations submitted in the PSD application, potential hazardous air pollutant emissions from all sources at the proposed Deer Creek generating station are less than 25 tons per year. Formaldehyde, with potential emissions of 4.5 tons per year, is the individual hazardous air pollutant emitted in the largest quantity. Because the facility does not have the potential to emit 10 tons or more per year of any single hazardous air pollutant and/or 25 tons per year or more of a combination of hazardous air pollutants, the Deer Creek generating station does not meet the definition of a major source of hazardous air pollutant emissions.

The Deer Creek generating station is an area source of hazardous air pollutants. In accordance with 40 CFR § 63.6590(2)(iii), a stationary reciprocating internal combustion engine at an area source of hazardous air pollutant emissions is new if construction commenced on or after June 12, 2006. As given in 40 CFR § 63.6590(c), a new stationary reciprocating internal combustion

engine at an area source must meet the requirements of this part by meeting the requirement of 40 CFR Part 60, Subpart IIII. No further requirements apply for such engines under this part.

5.3 Review of Other Regulations in 40 CFR Part 63

DENR reviewed the remaining sections in the maximum achievable control technology standards and did not identify any other standards applicable to the Deer Creek generating station.

6.0 New Source Review

ARSD 74:36:10:01 notes that new source review regulations in this chapter apply to areas of the state which are designated as nonattainment pursuant to the Clean Air Act for any pollutant regulated under the Clean Air Act. The Deer Creek generating station will be located near White, South Dakota, which is in attainment for all pollutants regulated under the Clean Air Act. Therefore, the Deer Creek generating station is not subject to New Source Review.

7.0 Prevention of Significant Deterioration

A prevention of significant deterioration (PSD) review applies to new major stationary sources and major modifications to existing major stationary sources in areas designated as attainment under Section 107 of the Clean Air Act for any regulated pollutant. The following is a list of regulated pollutants under the PSD program:

- Total suspended particulate (PM);
- Particulate with a diameter less than or equal to 10 microns (PM10);
- Particulate with a diameter less than or equal to 2.5 microns (PM2.5);
- Sulfur dioxide (SO_2);
- Nitrogen oxides (NO_x);
- Carbon monoxide (CO);
- Ozone – measured as volatile organic compounds (VOCs);
- Lead;
- Fluorides;
- Sulfuric acid mist;
- Hydrogen sulfide;
- Reduced sulfur compounds; and
- Total reduced sulfur.

If the source is considered one of the 28 named PSD source categories listed in Section 169 of the federal Clean Air Act, the major source threshold is 100 tons per year of any regulated pollutant. The major source threshold for all other sources is 250 tons per year of any regulated pollutant.

Fossil fuel-fired steam electric plants with a heat input greater than 250 million Btus per hour are one of the 28 named PSD source categories. Although combustion turbines are not included in this source category because they are not considered steam electric plants, fossil-fuel combustion in the heat recovery steam generator meets the definition of a steam electric plant. The maximum heat input to the duct burners at the Deer Creek generating station will be greater than 250 million Btus per hour. Therefore, the proposed Deer Creek generating station falls into one of the 28 named PSD source categories and will be considered a major source under the PSD program if it has the potential to emit greater than 100 tons per year of any regulated pollutant. Based on the potential emission calculations, the Deer Creek generating station has the potential to emit greater than 100 tons per year of nitrogen oxides and carbon monoxide. Therefore, the Deer Creek generating station is a major source under the PSD program and subject to PSD review.

Once a source is considered major, all regulated air pollutants emitted at a rate greater than the "significant" level are subject to PSD review. The PSD significant emission rates are given 40 CFR § 52.21(b)(23)(i) and summarized in Table 7-1, along with the potential emissions from the Deer Creek generating station. Based on the potential emissions, the Deer Creek generating station will be subject to PSD review for carbon monoxide, nitrogen oxides, and particulate matter (including PM10 and PM2.5).

Table 7-1 – Comparison of Potential Emissions and PSD Significant Emission Levels

Pollutant	Potential Emissions	PSD Significant Level	PSD Review
Carbon Monoxide	256 tons/year	25 tons/year	**Yes**
Nitrogen Oxides (NOx)	119 tons/year	40 tons/year	**Yes**
Sulfur Dioxide (SO_2)	12 tons/year	40 tons/year	No
PM [1]	80 tons/year	25 tons/year	**Yes**
PM_{10} [2]	80 tons/year	15 tons/year	**Yes**
$PM_{2.5}$ (measured directly) [3]	80 tons/year	10 tons/year	**Yes**
$PM_{2.5}$ (measured as NOx) [3]	119 tons/year	40 tons/year	**Yes**
$PM_{2.5}$ (measured as SO2) [3]	12 tons/year	40 tons/year	No
Ozone (measured as VOC)	30 tons/year	40 tons/year	No
Ozone (measured as NOx)	119 tons/year	40 tons/year	**Yes**
Lead	0.0 tons/year	0.6 tons/year	No
Sulfuric Acid Mist	2 tons/year	7 tons/year	No

[1] – For the combustion of natural gas in the combustion turbine/ heat recovery steam generator, all particulate emissions were assumed to have an aerodynamic diameter less than 2.5 microns. Therefore, PM, PM_{10}, and $PM_{2.5}$ emissions are assumed to be equal.
[2] – "PM_{10}" means particulate matter with a diameter 10 microns or less in diameter. The PM_{10} includes filterable and condensable; and
[3] – "$PM_{2.5}$" means particulate matter with a diameter 2.5 microns or less in diameter. The $PM_{2.5}$ includes filterable and condensable.

The federal PSD regulations were recently amended to add $PM_{2.5}$ as a regulated pollutant. On May 16, 2008, EPA published the final rule implementing the New Source Review program for $PM_{2.5}$. The final rule included the major source threshold and significant emissions rate for

$PM_{2.5}$. States with SIP-approved PSD programs (such as South Dakota) are required to submit revised PSD programs for $PM_{2.5}$ by May 2011. 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 program requires the applicant to control regulated emissions by using the Best Available Control Technology (BACT) and conduct impact modeling to demonstrate that emissions from the proposed source will not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) or exceed the PSD increment. A complete BACT analysis was completed for the control of nitrogen oxide, carbon monoxide, and particulate matter from the following emission sources:

- Natural Gas Combined Cycle (combustion turbine/heat recovery steam generator);
- Diesel-Fired Emergency Generator;
- Diesel-Fired Fire Water Pump; and
- Inlet Air Heater.

For the combustion of natural gas in the combustion turbine/heat recovery steam generator, all particulate emissions were assumed to have an aerodynamic diameter less than 2.5 microns. Therefore, PM, PM_{10}, and $PM_{2.5}$ emissions are assumed to be equal.

7.1 Best Available Control Technology (BACT) Analysis

The requirement to conduct a BACT analysis is set forth in 40 CFR § 52.21(j). The BACT requirement applies to each individual new or modified affected emissions unit and pollutant emitting activity at which a net emissions increase would occur. The BACT analysis consists of determining the best available controls and establishing an emissions limit (including a visible emission standard) based on the maximum degree of reduction achievable for each pollutant subject to regulation under the federal Clean Air Act. The BACT analysis is determined on a case-by-case basis taking into account energy, environmental, and economic impacts, and other costs. BACT is achievable through application of production processes or available methods, systems, and techniques, including fuel cleaning, treatment or innovative fuel combustion techniques for control of such pollutant. In no case shall application of BACT result in an emission limit for any pollutant that would be greater than the emission limit allowed by any applicable standard under 40 CFR Parts 60 and 61.

If DENR determines that technological or economic limitations on the application of a measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by the implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

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. The PSD regulations do not specify a specific BACT analysis process. Therefore, several processes may be used to

determine BACT. BEPC used EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990 ("NSR Manual") in its BACT analysis. The NSR Manual describes a "top-down" approach to the determination of BACT controls for new emission sources. 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.

The first step in the BACT analysis is to identify all available control options for the emission unit in question. 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.

The second step is to review the technical feasibility of the control options identified in the first step with respect to source-specific and unit-specific factors. A demonstration of technical infeasibility 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. Options that are technically infeasible are eliminated from further review.

DENR considers a control technology technically feasible if (1) it has been installed and operated successfully under similar conditions on the type of source under review, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: ''availability'' and ''applicability.'' A technology is considered ''available'' if the source owner may obtain it through commercial channels. An available technology is ''applicable'' if it can reasonably be installed and operated on the source type under consideration.

The typical stages for bringing a control technology concept to reality as a commercial product are: 1) Concept stage; 2) Research and patenting; 3) Bench scale or laboratory testing; 4) Pilot scale testing; 5) Licensing and commercial demonstration; and 6) Commercial sales. A control technique is considered available if it has reached the stage of licensing and commercial availability. DENR does not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. A technology at the pilot scale testing stage of development is not considered ''available'' for purposes of BACT. Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility also means a control option may reasonably be deployed on or ''applicable'' to the source type under consideration.

In the third step, all remaining control techniques identified in step one and not eliminated by step two are ranked in order of over all control effectiveness. The most effective control option is the system that achieves the lowest emissions level.

In step four, each technically feasible control option, beginning with the most effective, is evaluated for economic, energy, and environmental impacts. Both beneficial and adverse impacts should be assessed and quantified, if possible. 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.

DENR considered the following in its review of the applicant's BACT analysis, which is not all inclusive:

1. BEPC's PSD application;
2. EPA's Reasonably Available Control Technology, Best Available Control Technology and Lowest Achievable Emission Rate Clearinghouse (generally referred to as the RACT/BACT/LAER Clearinghouse or RBLC);
3. PSD permits issued to other combined cycle power plants in other states; and
4. Technical documents.

BEPC's proposed BACT emission limits and associated control technologies for the Deer Creek generating station are summarized in Tables 7-2 and 7-3.

Table 7-2 – Proposed Combined Cycle BACT Emission Limits and Control Technologies

Pollutant	Proposed BACT Emission Limits [1]	Proposed BACT Technology	Compliance Demonstration
NO_x	3.5 ppmvd @15% O_2 Based on a 30-day rolling average	Selective Catalytic Reduction (SCR)	NO_x continuous emission monitoring system
CO	9.0 ppmvd @15% O_2 (without duct firing) and 18.3 ppmvd @15% O_2 (with duct firing). Both limits based on a 30-day rolling average	Combustion controls	CO continuous emission monitoring system
Total PM (filterable and condensable)	18.6 lb/hr (without duct firing) 23.2 lb/hr (with duct firing)	Combustion controls	Stack Test, 40 CFR Part 60, Appendix A, Methods 201a/202 or the equivalent with DENR approval (average of 3 1-hour test runs)

[1] – "ppmvd @ 15% O_2 means parts per million by volume on a dry basis at 15 percent oxygen.

Table 7-3 – Proposed BACT Emission Limits and Control Technologies for Other Sources

Source	Proposed BACT Emission Limits	Proposed BACT Technology	Compliance Demonstration
Emergency Generator	Compliance with the applicable provisions in the compression ignition internal combustion engine NSPS	Combustion controls, low-sulfur diesel fuel and limited hours of operation	Compliance with the applicable provisions in the compression ignition internal combustion engine NSPS
Fire Water Pump	Compliance with the applicable provisions in the compression ignition internal combustion engine NSPS	Combustion controls, low-sulfur diesel fuel and limited hours of operation	Compliance with the applicable provisions in the compression ignition internal combustion engine NSPS
Inlet Air Heater	NO_x: 0.048 pounds/million Btus CO: 0.08 pounds/million Btus	Combustion controls and limited hours of operation	Operation in accordance with manufacturer's specifications

7.2 Combustion Turbine/Heat Recovery Steam Generator BACT Analysis

7.2.1 Nitrogen Oxide BACT for Combustion Turbine/Heat Recovery Steam Generator

After a comprehensive review of available information, BEPC identified the nitrogen oxide control technologies listed in Table 7-4, as having potential application to the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator. DENR agrees with the list of potential control options.

Table 7-4 – Potential NO_x Control Options

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

After evaluating the potentially available nitrogen oxide control technologies, BEPC identified water/steam injection, low-NOx combustion, and selective catalytic reduction (SCR) as technically feasible control options for the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator. BEPC indicated the remaining five post-combustion control technologies have not been demonstrated on a large natural gas-fired combustion turbine/heat recovery steam generator and are not considered technically feasible or commercially available.

The technically feasible nitrogen oxide control technologies are ranked in Table 7-5 with the lowest achievable emission rate ranked #1.

Table 7-5 – Ranking of Technically Feasible NO_x Control Technologies

Rank	Control Technology	Controlled NO_x Emission Rate (ppmvd @ 15%O_2) [1]
#1	Selective Catalytic Reduction	3.5
#2	Low-NO_x Combustion	15
#3	Water/Steam Injection	35

[1] "ppmvd @ 15% O_2" means parts per million by volume dry at 15% oxygen.

Combustion modifications designed to reduce nitrogen oxide formation, including lower temperatures and reduced oxygen availability, tend to increase the formation of carbon monoxide and volatile organic compounds. Therefore, combustion controls, including low-NOx burners, must be designed to reduce the formation of nitrogen oxide while maintaining carbon monoxide and volatile organic compound formation at acceptable levels. Other than this trade-off, there are no environmental issues associated with using combustion controls to reduce nitrogen oxide emissions from natural gas-fired combustion turbines.

A SCR system produces collateral environmental impacts. Excess ammonia will pass through the SCR. This is referred to as ammonia slip. Ammonia slip will increase as nitrogen oxide emissions are driven lower and will also increase as the catalyst becomes deactivated. BEPC stated that the ammonia slip from an SCR designed to achieve a controlled nitrogen oxide emission rate of 3.5 parts per million by volume dry (ppmvd) at 15% oxygen on a natural gas-fired combustion turbine should be in the range of 2 parts per million or less during initial operation. With catalyst age and deactivation, ammonia slip will increase; however, ammonia slip is not expected to exceed 5 parts per million under normal operating conditions.

Undesirable reactions may occur in an SCR system, including oxidation of ammonia and sulfur dioxide and the formation of ammonium sulfate salts. Approximately 4 percent of the sulfur dioxide in the flue gas will oxidize to sulfur trioxide in the presence of the SCR catalyst. Sulfur trioxide reacts with water to form sulfuric acid mist or with ammonia slip to form ammonium sulfate or bisulfate. Because sulfuric acid mist and ammonium sulfate are classified as condensable particulates, SCR can result in increased PM10 emissions. Natural gas is a low-sulfur fuel; therefore, the increase in condensable particulates will be minimal. Based on emission calculations, SCR with ammonia slip of 5 parts per million will increase potential condensable PM10 emissions by approximately 1.4 tons per year. The increase in condensable PM10 emissions is not considered significant enough to preclude the use of SCR for nitrogen oxide control.

Storage of ammonia on-site increases the risks associated with an accidental ammonia release. Chemical accidental release prevention requirements have been established in 40 CFR Part 68. Risk management requirements are triggered if more than a threshold quantity (20,000 pounds of aqueous ammonia or 10,000 pounds of anhydrous ammonia) will be stored on-site. A Risk Management Plan is required by the date on which a regulated substance is first present above the threshold quantity. In addition to a Risk Management Plan, under Section 112(r)(1) of the Clean Air Act, the source also has a general duty to identify, prevent, and minimize the consequences of an accidental release of toxic chemicals.

The most effective nitrogen oxide control system that is technically feasible for the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator consists of combustion controls and post-combustion SCR. This combination of control should be capable of achieving the most stringent controlled nitrogen oxide emission rate on a long-term basis. The effectiveness of SCR systems depends on several site-specific variables including the size of the SCR (i.e., the number of catalyst layers), the ammonia/nitrogen oxide stoichiometric ratio, acceptable ammonia slip, and the catalyst deactivation rate.

Based on an evaluation of available control technologies, BACT evaluations included in recently submitted PSD permit applications for similar sources, and BACT limits in recently issued PSD permits, a combination of low-NO_x combustion and post-combustion SCR represents BACT for nitrogen oxide control for the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator. BEPC is proposing SCR as BACT for nitrogen oxide control for the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator. BEPC proposed a controlled nitrogen oxide emission rate of 3.5 ppmvd at 15% oxygen or approximately 0.013 pounds per MMBtu on a 30-day rolling average. Because BEPC is proposing to use the most stringent nitrogen oxide control technology (i.e., the lowest emission rate), an economic evaluation of alternative nitrogen oxide control systems is not required.

DENR's review indicates that low-NOx combustion and post-combustion SCR represents BACT for NOx control for a natural gas combined cycle system. However, DENR disagrees with the proposed emission limit of 3.5 parts per million by volume on a dry basis corrected to 15% oxygen based on a 30-day rolling average. Table 7-6 summarizes recent natural gas combined cycle system BACT determinations for nitrogen oxide emissions.

Table 7-6 – Recent Nitrogen Oxide BACT Determinations

Facility	State	Permit Issued	Limit [1]	Period [2]	Method [3]
Diamond Wanapa	Oregon	August 8, 2005	2.0	3-hour	CEMs [4]
Treasure Coast	Florida	May 19, 2006	2.0 2.0	3-hour 24-hour	Stack Test CEMs [4]
Faribault Energy Park	Minnesota	June 5, 2007	3.0	3-hour	CEMs [4]
Rocky Mountain Energy	Colorado	July 1, 2007	3.0	1-hour	CEMs [4]
West County Energy	Florida	July 30, 2008	2.0 2.0	3-hour 24-hour	Stack Test CEMs [4]
Cane Island Power Park	Florida	September 8, 2008	2.0 2.0	3-hour 24-hour	Stack Test CEMs [4]

[1] – The limit is the emission limit based on parts per million by volume on a dry basis corrected to 15% oxygen, excluding startup and shutdown emissions;
[2] – The period is the compliance period associated with the emission limit;
[3] – The method is the compliance method used to demonstrate compliance with the emission limit; and
[4] – CEMs means continuous emission monitoring system.

As shown in Table 7-6, nitrogen oxide emission limits in recently issued permits have been based on a more stringent compliance period than a 30-day rolling average. In addition, the

nitrogen oxide emission limits are lower than BEPC proposed. The nitrogen oxide emission limit also varies depending on the facility location. Facilities located near South Dakota were permitted with a nitrogen oxide emission limit up to 3.0 parts per million by volume dry at 15% oxygen. Facilities located in warmer regions were permitted with a lower nitrogen oxide limit of 2.0 parts per million dry at 15% oxygen.

In the technical review (page TE-12) for the West County Energy Center, the Florida Department of Environmental Protection reviewed the continuous emission monitoring data from the Sithe Mystic Station in Massachusetts from December 2004. Excluding startup and shutdown emissions, Florida's review showed that the majority of the hourly nitrogen oxide emissions data were less than 2.0 parts per million by volume on a dry basis corrected to 15% oxygen. A few of the hourly data points were higher than 2.0 parts per million dry by volume at 15% oxygen, but all were less than 6.0 parts per million volume dry. Calculation of the 3-hour and 24-hour averages for periods excluding startup and shutdown indicate average values of approximately 3 and 2 parts per million by volume dry corrected to 15% oxygen, respectively.

In the technical review (page TE-16) for the Treasure Coast Energy Center, the Florida Department of Environmental Protection reviewed performance test data for Blackstone Energy Company in Massachusetts. The nitrogen oxide performance test results ranged from 1.4 to 1.7 parts per million by volume on a dry basis corrected to 15% oxygen. DENR reviewed EPA's clean air markets webpage located at http://www.epa.gov/airmarkets/index.html, which identifies the monitored nitrogen oxide emissions reported under the Acid Rain Program. The January 2008 hourly nitrogen oxide emissions data, excluding startup and shutdown, for the Blackstone Energy Company ranged from 0.006 to 0.007 pounds per million Btus, which is approximately 1.6 to 1.9 parts per million by volume on a dry basis corrected to 15% oxygen.

DENR reviewed the monitored data from January 2008 through March 2008 from EPA's clean air markets webpage for the Rocky Mountain Energy Center, Colorado. The hourly nitrogen oxide emissions data, excluding startup and shutdown, for the Rocky Mountain Energy Center ranged from 0.003 to 0.010 pounds per million Btus, which is approximately 0.8 to 2.7 parts per million by volume on a dry basis corrected to 15% oxygen. Based on averaging 24 hours of consecutive hourly nitrogen oxide emissions data, excluding startup and shutdown, the 24-hour average emissions ranged from 0.005 to 0.008 pounds per million Btus, which is approximately 1.4 to 2.2 parts per million by volume on a dry basis corrected to 15% oxygen.

DENR also reviewed the monitored data from January 2008 through March 2008 from EPA's clean air markets webpage for the Faribault Energy Park, Minnesota. The available hourly nitrogen oxide emissions data were for a simple cycle combustion turbine with the ability to burn natural gas and distillate oil. EPA's monitoring data did not distinguish between fuel types. However, based on the revised permit for Faribault Energy Park, the nitrogen oxide emission limit for the combined cycle combustion turbine while burning distillate oil is 6.0 parts per million by volume on a dry basis corrected to 15% oxygen. Therefore, it was assumed that the hourly nitrogen oxide emission data in the range of 5 to 6 parts per million by volume on a dry basis corrected to 15% oxygen represented distillate oil use. Excluding data associated with startup and shutdown and periods of distillate oil use, the hourly nitrogen oxide emissions data

for Faribault Energy Park ranged from 0.003 to 0.011 pounds per million Btus, which is approximately 0.8 to 3.0 parts per million by volume on a dry basis corrected to 15% oxygen.

DENR recommends the following nitrogen oxide emission limits as BACT for the Deer Creek station during normal operations excluding startup, shutdown, and malfunctions:

1) 3.0 parts per parts per million by volume on a dry basis corrected to 15% oxygen. Compliance based on a 3-hour average using the continuous emission monitoring system; and
2) 25.8 pounds per hour. Compliance based on a 3-hour average using the continuous emission monitoring system. This limit is based on 3.0 parts per parts per million by volume on a dry basis corrected to 15% oxygen (~ 0.0111 pounds per million Btus) at maximum capacity.

BEPC's BACT review, other issued PSD permits, and the monitoring data maintained on EPA's clean air markets webpage note that higher nitrogen oxide emissions are generated during startup and shutdown. The monitoring data reported on EPA's clean air markets webpage notes that emissions during a startup can be range as high as 0.12 to 0.56 pounds per million Btus, which is approximately 30 to 150 parts per million by volume on a dry basis corrected to 15% oxygen. BEPC proposed a BACT limit during startup and shutdown periods of 65.5 pounds per hour based on a 24-hour average.

States vary in their approach to limiting emissions during startup and shutdown. For example, Minnesota limited startup and shutdown periods to 1255 hours per 12-month period in the permit for the Faribault Energy Park. The permit for the West County Energy Center in Florida limits excess emissions during startup and shutdown to 2 to 8 hours in a 24-hour period, depending on the operating scenario. The nitrogen oxide emission limit during startup and shutdown for the Rocky Mountain Energy Center in Colorado is 300 parts per million volume on a dry basis corrected to 15% oxygen.

DENR recommends the following nitrogen oxide emission limits as BACT during startup and shutdown:

1) 220 pounds of nitrogen oxide emissions. This limit is based on the emission estimates provided for a cold startup. Compliance based on each startup or shutdown period using the continuous emission monitoring system;
2) 708 hours of operation. This limit is based on the number of hours listed for startup in BEPC's application. Compliance based on a 12-month rolling period;
3) 117 tons of nitrogen oxide emissions. Compliance based on a 12-month rolling period using the continuous emission monitoring system for all periods of operation, including startup and shutdown; and
4) Define startup and shutdown and require a startup, shutdown, and malfunction plan.

7.2.2 Carbon Monoxide BACT for Combustion Turbine

Carbon monoxide emissions result from incomplete fuel combustion. Improper fuel-to-air ratio, inadequate fuel mixing, low combustion temperatures, and reduced excess oxygen all influence carbon monoxide formation. Combustion turbine operation at lower loads (below 50%) can also impact combustion controls and carbon monoxide formation.

Based on a comprehensive review of available information, BEPC identified the carbon monoxide control technologies listed in Table 7-7, as having potential application to the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator. DENR agrees with the list of control options.

Table 7-7 – Potential CO Control Options

Combustion Controls
Combustion Controls
Post-Combustion Controls
Oxidation Catalyst
Oxidation Catalyst with Potassium Carbonate Absorption (EMx™ formerly SCONOx™)
Catalytic Combustion (Xonon™)

Carbon monoxide control technologies fall into two general categories: combustion controls and post-combustion controls. Combustion controls designed to minimize nitrogen oxide formation, including lower peak combustion temperatures and less excess oxygen, tend to increase the formation of carbon monoxide emissions. Burner vendors attempt to address these issues by improving fuel-air mixing and ensuring adequate residence time in the combustion zone. Improved mixing minimizes the potential for fuel-rich areas and the formation of carbon monoxide. Increased residence time in the combustion zone reduces carbon monoxide formation by providing the oxygen necessary for more complete combustion. Minimizing carbon monoxide emissions is desirable from an economic standpoint because carbon monoxide represents unutilized energy exiting the process.

A combination of low-NOx burners and SCR is considered BACT for controlling nitrogen oxide emissions. BEPC stated that the low-NOx burners proposed for the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator should be able to maintain an average carbon monoxide concentration of 9.0 parts per million by volume dry (ppmvd) (approximately 7.4 ppmvd at 15% oxygen). A concentration of 9.0 ppmvd is equivalent to a carbon monoxide emission rate of approximately 0.017 pounds per million Btu heat input.

Duct burners are direct-fired gas burners located in the turbine exhaust stream where it is challenging to control combustion conditions. Duct firing tends to increase carbon monoxide emissions from the unit. Combustion conditions in the heat recovery steam generator vary depending on exhaust gas temperature and velocity, uniformity of the exhaust gas flow, and the oxygen and moisture content of the exhaust gas. BEPC stated that carbon monoxide emissions associated with the most current low-NOx duct burner designs can be limited to 0.05 pounds per million Btu heat input to the duct burner while maintaining nitrogen oxide emissions at approximately 15 ppmvd at 15% oxygen. Based on emission calculations at full load heat input

to the combustion turbine and maximum duct firing (annual average ambient conditions), duct firing will increase carbon monoxide emissions in the exhaust from 9.0 to 18.3 ppmvd or approximately 0.025 pounds per million Btu total heat input to the combustion turbine and duct burner.

Of the three post-combustion carbon monoxide control technologies listed in Table 7-7, only catalytic oxidation is considered technically feasible and commercially available for the proposed Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator. At this time, neither the oxidation catalyst with potassium carbonate absorption (EMx™ formerly SCONOx™) or the catalytic combustion (Xonon™) control technologies have been successfully demonstrated on a large natural gas-fired combustion turbine. Therefore, neither technology is considered an available carbon monoxide control technology and will not be further evaluated as BACT for carbon monoxide.

In a catalytic oxidation system, carbon monoxide is oxidized to carbon dioxide using a noble metal catalyst which promotes the oxidation of carbon monoxide at temperatures approximately 50% lower than those required without the catalyst. The operating range for commercially available oxidation catalysts is between 650 and 1,150°F, which typically occur in the heat recovery steam generator on a natural gas-fired combustion turbine. On units equipped with SCR, the catalytic oxidation system is installed immediately upstream of the SCR.

Catalyst efficiency depends on inlet carbon monoxide concentration, inlet gas temperature, and flue gas residence time. Generally, removal efficiency increases with increased flue gas temperature and increased catalyst bed depth. Catalytic oxidation systems have been installed on natural gas-fired combined cycle units and have been demonstrated to effectively reduce carbon monoxide emissions. In natural gas turbine applications, catalytic oxidation systems have demonstrated the ability to achieve controlled carbon monoxide emissions of 2.0 ppmvd @ 15% oxygen. Reduction efficiencies of 70 to 90% have been demonstrated depending on the inlet carbon monoxide concentration.

Catalytic oxidation is considered a technically feasible and commercially available carbon monoxide control technology for the proposed Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator. Based on emission rates achieved in practice at similar sources, BEPC stated that a controlled carbon monoxide emission rate of 3.3 ppmvd (approximately 2.0 ppmvd at 15% oxygen) is achievable with a catalytic oxidation system. Based on calculated emission rates of 9.0 ppmvd (without duct firing) and 18.3 ppmvd (with duct firing), the catalytic oxidation system would achieve a carbon monoxide removal efficiency of 63% (without duct firing) and 82% (with duct firing).

The technically feasible carbon monoxide control technologies are ranked in Table 7-8 with the lowest achievable emission rate ranked #1.

Table 7-8 – Ranking of Technically Feasible CO Control Technologies

Rank	Control Technology	Controlled CO Emission Rate (ppmvd) [1]
#1	Catalytic Oxidation	3.3

#2	Combustion Controls	9.0 (without duct firing) 18.3 (with duct firing)

[1] – "ppmvd" means parts per million by volume dry.

BEPC performed an analysis of the economic impact associated with including a catalytic oxidation control system with the low-NOx burners. Projected annual emissions (tons per year) were used to evaluate the average cost effectiveness (dollar per ton carbon monoxide removed). Annual emissions (tons per year) 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 per year; and (3) startup/shutdown emissions for the remaining 708 hours. In its economic analysis, BEPC determined that an additional 144.2 tons per year of carbon monoxide would be removed using a catalytic oxidation system in addition to low-NOx burners.

The total annual cost of the catalytic oxidation control system was estimated at $479,300 or $3,324 per ton of carbon monoxide removed. Equipment, energy, and operating (i.e., routine catalyst replacement) costs all have a significant impact on the cost of a catalytic oxidation control system. Based on the significant economic impact associated with the installation and operation of a catalytic oxidation control system, the limited cost effectiveness, and the collateral environmental and energy impacts, BEPC concluded that post-combustion catalytic oxidation should be eliminated as BACT for carbon monoxide for the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator.

DENR conducted a search of EPA's RACT/BACT/LAER (RBLC) database for carbon monoxide BACT requirements in recently issued PSD permits for natural gas-fired combined cycle combustion turbines. A list of facilities and the carbon monoxide BACT determinations from the RBLC database are given in Table 7-8 in chronological order.

Table 7-8 – Carbon Monoxide BACT for Combustion Turbines

Date	Facility	BACT	Notes
12/01/04	Wellton Mohawk Generating Station – Yuma, Arizona	Catalytic oxidation system	Permitted with the option to use either General Electric 7FA combustion turbine generators or Siemens-Westinghouse combustion turbine generators. The cost effectiveness of using catalytic oxidation at this facility was calculated at $5,695 per ton for the General Electric combustion turbine option and $1,988 per ton for the Siemens-Westinghouse turbines.
02/08/05	Florida Power and Light Turkey Point Power Plant	Good combustion controls	
06/08/05	Progress Energy Hines Power Block 4 – Florida	Good combustion controls	

08/08/05	Diamond Wanapa - Oregon	Catalytic oxidation system	Cost effectiveness of $1,161 per ton of carbon monoxide removed.
08/15/05	Tracy Substation expansion – Nevada	Catalytic oxidation system	Cost effectiveness of $2,736 per ton of carbon monoxide removed.
05/16/06	Northern States Power d.b.a. Xcel Energy – Riverside Power Plant – Minnesota	Good combustion controls	A catalytic oxidation system was rejected because of a cost effectiveness of $7,670 per ton of carbon monoxide removed.
01/26/07	Progress Bartow Power Plant – Florida	Good combustion controls	
06/05/07	Fairbault Energy Park – Minnesota	Good combustion controls	
01/07/08	Georgia Power's Plant McDonough – Georgia	Catalytic oxidation system	Cost effectiveness of $1,750 per ton of carbon monoxide removed.
03/20/08	Arsenal Hill Power Plant – Louisiana	Good combustion controls	

Catalytic oxidation and good combustion controls have been intermittently identified as BACT for carbon monoxide by states over the last 5-6 years. Catalytic oxidation has been required for carbon monoxide control on units with a cost effectiveness ranging from as high as $5,695 per ton of carbon monoxide removed to as low as $1,161 per ton. As discussed above, several recently issued PSD permits have been issued with good combustion controls as BACT for carbon monoxide and in one case rejecting a catalytic oxidation system at a cost of removal of $7,670 per ton.

DENR reviewed GE Power Systems' June 2001 white paper entitled "Support for Elimination of Oxidation Catalyst Requirements." In the paper, GE states that there has not been a consistent determination of the cost effectiveness of catalytic oxidation for the control of carbon monoxide. The paper notes several projects for which catalytic oxidation was not considered cost effective in the range of $2,000 to $7,400 per ton of carbon monoxide removed. In the white paper, GE reported that EPA Region II considered catalytic oxidation cost effective at $6,000 per ton of emission reduction. The paper also states that GE has offered a carbon monoxide emission guarantee of 5.0 parts per million by volume dry on a case-by-case basis. In addition, GE notes that its turbines have consistently operated at carbon monoxide emission levels less than 9 parts per million by volume at base load. Using EPA's value of $6,000 per ton of emission reduction, GE indicates that a turbine would have to have emission limits less than 7.0 parts per million to be considered cost effective.
Table 7-9 summarizes recent natural gas combined cycle system carbon monoxide BACT determinations as given in the permit for each facility.

Table 7-9 – Recent Carbon Monoxide BACT Determinations

Facility	State	Permit Issued	Limit [1]	Period [2]	Method [3]
Diamond Wanapa	Oregon	August 8, 2005	2.0 [6]	3-hour	CEMs [4]
Riverside Generating Plant	Minnesota	May 2, 2006	10.0 [6]	3-hour	CEMs [4]
Treasure Coast	Florida	May 19, 2006	4.1 [5] 8.0 [5] 7.6 [6] 8.0 [6]	3-hour 24-hour 3-hour 24-hour	Stack Test CEMs [4] Stack Test CEMs [4]
Faribault Energy Park	Minnesota	June 5, 2007	9.0 [5] 11.0 [6]	3-hour	CEMs [4]
Rocky Mountain Energy	Colorado	July 1, 2007	9.0 [6]	3-hour	CEMs [4]
McDonough	Georgia	January 7, 2008	1.8 [6]	3-hour	Stack Test and CEMs [4]
West County Energy	Florida	July 30, 2008	4.1 [5] 8.0 [5] 7.6 [6] 8.0 [6]	3-hour 24-hour 3-hour 24-hour	Stack Test CEMs [4] Stack Test CEMs [4]

[1] – The limit is the emission limit based on parts per million by volume on a dry basis corrected to 15% oxygen, excluding startup and shutdown emissions;
[2] – The period is the compliance period associated with the emission limit;
[3] – The method is the compliance method used to demonstrate compliance with the emission limit;
[4] – CEMs means continuous emission monitoring system;
[5] – The limit is for the combustion turbine only; and
[6] – The limit is for the combustion turbine and duct burner.

BEPC determined the cost of carbon monoxide removal using catalytic oxidation for the Deer Creek generating station as $3,324 per ton. This is within the cost effectiveness range that other states and the EPA have approved catalytic oxidation as BACT. As noted in other reviews, states have considered that catalytic oxidation is not cost effective for removing carbon monoxide because the removal efficiency decreases significantly during periods of startup and shutdown and combustion turbines would not operate anywhere near 8,760 hours per year. However, BEPC requested 8,760 hours of operation for the combustion turbine in the application and attributes emissions reductions during startup and shutdown to the use of a catalytic oxidation system. Therefore, BACT for carbon monoxide for the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator shall be a catalytic oxidation system.

DENR recommends the following carbon monoxide emission limits as BACT during normal operations excluding startup, shutdown, and malfunctions:

1) 2.0 parts per parts per million by volume on a dry basis corrected to 15% oxygen. Compliance based on a 3-hour average using the continuous emission monitoring system; and
2) 10.5 pounds per hour. Compliance based on a 3-hour average using the continuous emission monitoring system. This limit is based on 2.0 parts per parts per million by

volume on a dry basis corrected to 15% oxygen (~ 0.0045 pounds per million Btus) at maximum capacity.

BEPC's BACT review and other issued PSD permits note that higher carbon monoxide emissions are generated during startup and shutdown. BEPC's proposed carbon monoxide BACT limit is 337.1 pounds per hour based on a 24-hour average and 243.3 tons per year for all periods, including startup and shutdown.

States vary in their approach to limiting emissions during startup and shutdown. For example, Minnesota limited startup and shutdown periods to 1,255 hours per 12-month period in the permit for the Faribault Energy Park. The permit for the West County Energy Center in Florida limits excess emissions during startup and shutdown to 2 to 8 hours in a 24-hour period, depending on the operating scenario. The carbon monoxide emission limit during startup and shutdown for the Rocky Mountain Energy Center in Colorado is 1000 parts per million volume on a dry basis corrected to 15% oxygen.

DENR recommends the following carbon monoxide emission limits as BACT during startup and shutdown:

1) 840 pounds of carbon monoxide emissions. This limit is based on the emission estimates provided for a cold startup. Compliance based on each startup or shutdown period using the continuous emission monitoring system;
2) 708 hours of operation. This limit is based on the number of startup hours given by BEPC in the PSD application. Compliance based on a 12-month rolling period;
3) 243 tons of carbon monoxide emissions. Compliance based on a 12-month rolling period using the continuous emission monitoring system for all periods of operation, including startup and shutdown; and
4) Define startup and shutdown and require a startup, shutdown, and malfunction plan.

7.2.3 Particulate Matter BACT for Combustion Turbine

Particulate emissions are classified as filterable or condensable. Filterable emissions are generally considered to be the particles captured by the filter in the front-half of a 40 CFR Part 60, Appendix A, Method 5 or Method 17 sampling train. Condensable particulate matter is material that is emitted in the vapor state which later condenses to form aerosol particulates. Particulate matter from natural gas combustion is generally larger molecular weight hydrocarbons that are not fully combusted, and may result from poor air/fuel mixing or maintenance issues.

Total particulate matter (including filterable and condensable) from natural gas combustion are generally assumed to be less than 1.0 micrometer in size. For the BACT evaluation, it is assumed that all particulate matter emitted from the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator is smaller than 2.5 micrometers. Therefore, particulate matter, PM10, and PM2.5 emission rates are equal.

Natural gas is an inherently clean fuel and particulate matter emissions from firing natural gas are minimal. Potentially available particulate matter control options include mechanical collectors, wet scrubbers, electrostatic precipitators (ESPs), and fabric filter baghouses. Particulate matter control systems have been designed primarily for use on boilers firing fuels that generate a significant amount of uncontrolled particulate matter including coal and distillate and residual oils. Since the uncontrolled particulate matter emissions with natural gas firing are typically below the controlled emission rates achieved with particulate control systems, particulate matter control systems have not been used in natural gas-fired applications. Therefore, due to the inherently low particulate emissions associated with firing natural gas, post-combustion control systems have no practical application for the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator.

BEPC is proposing natural gas firing and combustion controls as BACT for the Deer Creek generating station's natural gas-fired combustion turbine/heat recovery steam generator. BEPC is proposing a total particulate matter emission rate of 18.6 pounds per hour (approximately 0.01 pounds per MMBtu) at full load without duct firing and 23.2 pounds per hour (approximately 0.01 pounds per MMBtu) at full load with duct firing. The proposed emission rates include both filterable and condensable particulate matter, including condensable particulate from the SCR system.

A review of EPA's RBLC database shows that all recently permitted natural gas-fired combined cycle units have been permitted with combustion controls as BACT for particulate matter.

Table 7-10 summarizes recent natural gas combined cycle system BACT determinations for particulate matter based on each facility's permit.

Table 7-10 – Recent Particulate Matter BACT Determinations

Facility	State	Permit Issued	Limit	Period [3]	Method [4]
Treasure Coast	Florida	May 19, 2006	10% and 2 [2]		
Faribault Energy Park	Minnesota	June 5, 2007	0.01 [1]	3-hour	Stack Test
Rocky Mountain Energy	Colorado	July 1, 2007	0.00735[1]	3-hour	Stack Test
West County Energy	Florida	July 30, 2008	10% and 2 [2]		

[1] – The limit is the emission limit based on pounds per million Btus;
[2] – The limit is the emission limit based on percent opacity and grains of sulfur per 100 cubic feet of gas;
[3] – The period is the compliance period associated with the emission limit; and
[4] – The method is the compliance method used to demonstrate compliance with the emission limit.

The emission limits proposed by BEPC are comparable to those for natural gas-fired combined cycle units in the RBLC database. There are no adverse environmental or energy impacts associated with the proposed BACT for particulate matter.

DENR recommends the following particulate matter emission limits as BACT during normal operations excluding startup, shutdown, and malfunctions:

1) 0.01 pounds per million Btus. Compliance based on a 3-hour average using a performance test;
2) 18.6 pounds per hour for the combustion turbine only. Compliance based on a 3-hour average using a performance test;
3) 23.2 pounds per hour for the combustion turbine and duct burner. Compliance based on a 3-hour average using a performance test; and
4) Fuel usage limited to pipeline natural gas with the sulfur content of the natural gas defined.

BEPC's BACT review and other issued PSD permits note higher particulate matter emission limits based on a pound per million Btus basis. DENR proposes the following BACT limits to include startup and shutdown emissions:

1) 18.6 pounds per hour for the combustion turbine only. Compliance based on the use of pipeline natural gas and a startup, shutdown, and malfunction plan;
2) 23.2 pounds per hour for the combustion turbine and duct burner. Compliance based on the use of pipeline natural gas and a startup, shutdown, and malfunction plan;
3) 708 hours of operation. This limit is based on the number of hours BEPC gave for startup in the PSD application. Compliance based on a 12-month rolling period;
4) 80 tons. Compliance based on a 12-month rolling period using emission factors and emission calculations developed from compliance testing;
5) Fuel usage limited to pipeline natural gas with the sulfur content of pipeline natural gas defined; and
6) Define startup and shutdown and require a startup, shutdown, and malfunction plan.

7.3 Emergency Generator and Fire Water Pump BACT Analysis

The Deer Creek generating station will have an emergency diesel generator which 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 emergency diesel generator will be designed to provide 2,000 kilowatts of power. The Deer Creek generating station will also be equipped with an emergency fire water pump. The fire water pump will be designed at 577 horsepower to provide a water flow rate of 3,000 gallons per minute.

The development of emission control technology for engines has primarily focused on reducing nitrogen oxide and carbon monoxide emissions since these are the primary pollutants from compression ignition engines. The most common control techniques for diesel compression ignition engines are to modify the combustion process to minimize nitrogen oxide formation and the products of incomplete combustion, including carbon monoxide and hydrocarbons. Recently, post-combustion absorption systems and catalytic reduction systems have become available for non-road and stationary diesel-fired compression ignition engines. Potentially feasible combustion controls and post-combustion controls are summarized in the following sections.

7.3.1 Combustion Controls

From an emissions standpoint, the most important distinction between different compression ignition engines is whether they are rich-burn or lean-burn. Rich-burn engines operate with a near stoichiometric or fuel-rich of stoichiometric air-to-fuel ratio. 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. Therefore, the exhaust gas is characterized by mid- to high-levels of oxygen. Diesel engines are inherently lean-burn engines.

Combustion modifications designed to minimize emissions from compression ignition engines include injection timing retard, adjusting the air-to-fuel ratio, and de-rating. The injection of diesel fuel into the cylinder of a compression ignition engine initiates the combustion process. By retarding the timing of the injection of diesel fuel into the cylinder, the combustion process occurs later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. The increased volume results in lower combustion temperature and pressure, reducing nitrogen oxide formation.

The air-to fuel ratio can be adjusted by controlling the amount of fuel that enters each cylinder. Compression ignition 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, thereby lowering nitrogen oxide formation. De-rating involves restricting engine operation to lower than normal levels of power production for a given operation. De-rating reduces cylinder pressures and temperatures, lowering nitrogen oxide formation rates.

Combustion controls continue to develop for large stationary and non-road diesel engines. Combustion controls have demonstrated the ability to reduce nitrogen oxide emissions from compression ignition engines by approximately 50%. Based on AP-42 emission factors (Table 3.4-1), injection timing retard can reduce nitrogen oxide emissions from large stationary diesel-fired engines from approximately 10.9 grams/horsepower-hour (g/hp-hr) to approximately 5.9 g/hp-hr.

7.3.2 Post-Combustion Emission Control Technologies

Post-combustion absorption systems and catalytic reduction systems are becoming available for diesel-fired stationary compression ignition engines. A list of potentially feasible post-combustion control technologies applicable to large stationary diesel-fired compression ignition engines is given in Table 7-11. The potentially feasible control technologies are described in the following sections.

Table 7-11 – Potentially Feasible Post-Combustion CI Emission Control Technologies

Control Technology	Target Pollutants
Nitrogen oxide absorbers	Nitrogen oxide
Nonselective catalytic reduction	Nitrogen oxide, carbon monoxide, and non-methane hydrocarbons
Lean-NO_x catalyst	Nitrogen oxide

Control Technology	Target Pollutants
Oxidation catalyst	Carbon monoxide and non-methane hydrocarbons
SCR catalyst	Nitrogen oxide
Diesel particulate filter	Particulate matter
Catalytic diesel particulate filter	Particulate matter, carbon monoxide, and non-methane hydrocarbons

7.3.2.1 NO_x Absorption Systems

Post-combustion nitrogen oxide absorption systems have been developed to remove nitrogen oxide from compression ignition engine exhaust. In post-combustion nitrogen oxide absorption systems, nitrogen oxide is absorbed on a storage catalyst from which it is periodically reduced during the regeneration process. The process of trapping nitrogen oxide can be either catalytic absorption or adsorption. Catalyst regeneration and nitrogen oxide reduction is typically accomplished by injecting additional fuel just before the catalyst. This creates conditions that enable reduction of the nitrogen oxide using a precious metal catalyst that does not work under lean conditions. Catalyst life is an issue with current nitrogen oxide absorption systems. Currently available nitrogen oxide absorption catalysts have been very sensitive to poisoning by sulfur. Oxides of sulfur occupy sites on the catalyst and can only be removed using very high temperatures. Using low sulfur fuels, and development of sulfur traps in conjunction with more sulfur tolerant nitrogen oxide absorption catalysts will help alleviate catalyst poisoning by sulfur.

7.3.2.2 Catalytic Reduction Systems

Catalytic reduction systems are in various stages of development to reduce nitrogen oxide, carbon monoxide, and non-methane hydrocarbon emissions from stationary internal combustion engines. The principal behind using catalysts for the control of gaseous emissions from stationary internal combustion engines is to create reducing conditions at lower 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.

Nonselective catalytic reduction systems (NSCR) have been developed to reduce nitrogen oxide, carbon monoxide, and non-methane hydrocarbon emissions from engines that are operated stoichiometrically or fuel-rich of stoichiometric. In the presence of carbon monoxide and non-methane hydrocarbon in the engine exhaust, the catalyst in a NSCR system converts nitrogen oxide to nitrogen and oxygen, carbon monoxide to oxygen, and non-methane hydrocarbon to carbon dioxide and water. NSCR reactions require low oxygen levels and operating the engine at fuel-rich air-to-fuel ratios. Nitrogen oxide conversion efficiencies drop dramatically in lean-burn engines. Lean-burn engines are characterized by an oxygen-rich exhaust, minimizing the potential for nitrogen oxide reduction.

Research and development has been conducted on lean nitrogen oxide catalysts. Lean nitrogen oxide catalysts are designed to reduce nitrogen oxide to nitrogen and water in an oxygen-rich environment. Although the technology is relatively new, catalyst formulations and substructures have been developed that can reduce nitrogen oxide emissions in the oxygen-rich diesel exhaust environment. However, durability of the catalyst substructures has proven to be a challenge.

Catalyst development continues with both base metal and precious metal catalysts. Injection of a small amount of reducing agent upstream of the catalyst may improve lean-NO_x catalyst performance and durability.

Oxidation catalysts containing precious metals impregnated onto high geometric surface area substrates have been used on off-road mobile source lean-burn engines. Oxidation catalysts have proven effective in controlling carbon monoxide and non-methane hydrocarbon emissions from mobile source compression ignition engines and may also reduce particulate emissions from diesel engines by oxidizing the soluble organic faction of the particulate. Issues 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 under development to control nitrogen oxide emissions from stationary compression ignition engines. In SCR systems, a reducing agent such as ammonia or urea is introduced into the diesel exhaust over a catalyst. The purpose of the catalyst is to reduce the temperature required to initiate the reaction between the reducing agent and nitrogen oxide to produce nitrogen and water. Precious metal catalysts, typically vanadium and titanium, are used for exhaust gas temperatures between 450 °F and 800°F. For temperatures between 675°F and 1100°F, zeolite catalysts may be used. Components in the exhaust gas, including sulfur compounds, may result in catalyst deactivation and poisoning.

With all catalyst systems, including SCR, oxidation, or lean-NO_x catalytic control on an internal combustion engine, conditions exist that can reduce catalyst activity. Catalyst deactivation may result from chemical poisoning, masking, or thermal sintering. In most cases, reduced catalyst performance is due to masking of the catalyst by contaminants in the exhaust. Oxides of sulfur and particulates are contaminants in diesel-fired compression ignition exhaust. Deactivated catalysts are less effective at reducing the target pollutants. Spent catalysts must be properly managed to prevent improper disposal.

7.3.2.3 Particulate Control Systems

Diesel particulate emissions are composed of a variety of liquid phase hydrocarbons and solid phase soot (carbon). Diesel particulate filter systems consisting of a wall-flow type filter positioned in the exhaust stream have been developed to control particulate matter emissions from stationary diesel engines. As particulate matter collects on the filter media, the flow through the filter may be impeded, resulting in increased backpressure and reduced engine efficiency. When the backpressure reaches a certain level, the filter must be cleaned or regenerated. Thermal regeneration is accomplished by periodically enriching the air-to-fuel mixture, producing a higher exhaust gas temperature to burn off the particulate matter captured in the filter. Thermal regeneration of diesel particulate filters typically requires temperatures above 600°F, which may lead to uncontrolled ignition of soot and damage to the filter substrate.

Catalytic regeneration systems using precious and base metal catalysts have been developed to reduce the filter regeneration temperature in catalyzed diesel particulate filter control systems. Catalysts reduce the temperature required to oxidize particulate matter collected in the filter, reducing the potential for temperature overshoot and substrate damage. Catalyzed diesel

particulate filter catalysts are in development with high activity toward oxidation of carbon monoxide, hydrocarbon, and soot, and low activity for oxygen oxidation.

On July 11, 2006, the EPA promulgated a rule to reduce emissions of air pollutants from stationary compression ignition internal combustion engines. The Stationary Compression Ignition Combustion Engine New Source Performance Standard limits emissions of nitrogen oxide, particulate matter, sulfur dioxide, carbon monoxide, and hydrocarbon from stationary diesel internal combustion engines. As part of the rulemaking process, the EPA evaluated the technical feasibility, effectiveness, and cost effectiveness of potentially feasible control technologies, including those discussed above. The NSPS emission standards were based on the best demonstrated system of continuous emissions reduction, considering costs, non-air quality health, and environmental and energy impacts.

As part of the NSPS rulemaking process, the EPA evaluated the cost-effectiveness of potentially feasible post-combustion emission control systems. Cost-effectiveness calculations were prepared for various compression ignition engines based the horsepower rating and mode of operation (i.e., continuous or emergency). Post-combustion control technologies evaluated by EPA included nitrogen oxide absorbers, SCR, and catalyzed diesel particulate filters. The EPA also evaluated the cost per ton of particulate removal using oxidation catalyst. Based on the economic impact evaluations prepared by the EPA, post-combustion controls are not currently cost effective for emergency stationary compression ignition engines.

The NSPS requires emergency compression ignition internal combustion engines to meet the most stringent emission standards that do not require add-on control. The NSPS for compression ignition engines takes into account that emergency engines require control technologies with the highest degree of reliability while in standby mode and that require minimal time and adjustments to bring online. Post-combustion emission control systems are relatively expensive, require additional maintenance, and provide minimal annual emission reductions on units that are used infrequently. Commercial availability of post-combustion control technologies is limited, and post-combustion control systems are not economically feasible for emergency stationary compression ignition engines.

BEPC is proposing ultra low sulfur diesel fuel, combustion controls, and limited annual hours of operation as BACT for the emergency diesel generator and fire water pump. DENR agrees with this analysis. Therefore, BEPC will be required to meet the applicable compression ignition internal combustion engines NSPS emission standards as given in Tables 7-12 and 7-13.

Table 7-12 – Applicable CI ICE NSPS Emission Standards for Emergency Generator

	NO_x	**HC**	**NMHC + NO_x**	**CO**	**PM**
kW>560	**grams/kilowatt-hour (grams/horsepower-hour)**				
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)

Table 7-13 – Applicable CI ICE NSPS Emission Standards for Fire Water Pump

Maximum Engine Power	Model Year(s)	NMHC and NOx	CO	PM
		grams/kilowatt-hour (grams/horsepower-hour)		
225 ≤ KW < 450 (300 ≤ HP < 600)	2009+ [6]	4.0 (3.0)	3.5 (2.6)	0.2 (0.15)

7.4 Inlet Air Heater BACT Analysis

A natural gas-fired air inlet heater will be used to preheat the combustion turbine intake air during extremely cold ambient conditions (i.e., ambient temperatures less than approximately minus 25°F). The heater will be designed with a maximum heat input of 25.0 million Btus per hour to provide a heat duty of 19.0 million Btus per hour.

Potential emissions associated with the combustion of natural gas include nitrogen oxide, carbon monoxide, particulate matter, and sulfur dioxide. Nitrogen oxides are produced in the high-temperature post-flame region of the combustion zone from the oxidation of atmospheric nitrogen in the inlet air. Thermal nitrogen oxide formation is primarily affected by flame temperature and the quantity of excess air. Carbon monoxide emissions are generally associated with incomplete combustion. Particulate matter and sulfur dioxide emissions from the combustion of natural gas are minimal.

Low-NO_x burners limit nitrogen oxide formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Lower nitrogen oxide emissions are 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.

Combustion controls designed to reduce nitrogen oxide formation can adversely affect carbon monoxide emissions. Cooler flame and reduced oxygen availability tend to increase the formation of carbon monoxide. Carbon monoxide formation is minimized when the boiler temperature and excess oxygen availability are adequate for complete combustion. Proper burner design and operation can minimize carbon monoxide emissions while maintaining nitrogen oxide emissions at acceptable levels.

All the recently permitted natural gas-fired process heaters included in the RBLC database were permitted with combustion controls as BACT for nitrogen oxide and carbon monoxide. Post-combustion controls, such as selective catalytic reduction and catalytic oxidation systems, although potentially technically feasible, have not been demonstrated in practice and have not been permitted or installed on small natural gas-fired heaters to further reduce nitrogen oxide and carbon monoxide emissions. Therefore, BEPC did not evaluate post-combustion controls for the inlet air heater.

Permitted nitrogen oxide emission limits listed in the RBLC database for natural gas-fired heaters similar in size to the proposed inlet air heater (approximately 15 to 35 million Btus per hour heat input) range from 0.045 to approximately 0.13 pounds per million Btu. All the units

were permitted with combustion controls as BACT for nitrogen oxide. The controlled emission rates are similar to the AP-42 emission factor for small natural gas-fired boilers equipped with low-NO_x burners (50 pounds per million standard cubic foot or 0.049 pounds per million Btu, AP-42, Table 1.4-1).

Permitted carbon monoxide emission limits listed in the RBLC database for natural gas-fired heaters similar in size to the proposed inlet air heater range from 0.08 to approximately 0.1 pounds per MMBtus. All of the units were permitted with combustion controls as BACT for carbon monoxide. The controlled emission rate is similar to the emission factor for carbon monoxide in AP-42 (Table 1.4-1) for small natural gas-fired boilers equipped with low-NO_x burners (84 pounds per million standard cubic foot or 0.08 pound per million Btu).

BEPC is proposing ultra low sulfur diesel fuel, combustion controls, and limited hours of operation as BACT for the inlet air heater. Based on a review of available information, including emission limits from recently issued PSD permits for similar units, BEPC is proposing the following nitrogen oxide and carbon monoxide limits for the inlet air heater:

- Nitrogen oxide: 50 pounds per million standard cubic foot or 0.048 pounds per million Btu; and
- Carbon monoxide: 84 pounds per million standard cubic foot or 0.08 pounds per million Btu.

DENR agrees with BEPC's proposed emission limits. DENR also proposes to include an operational limit of 150 hours per 12-month rolling period. Compliance with the limit would be based on operational data.

7.5 Air Quality Analysis

The air quality analysis must satisfy the following three criteria before the construction of a major source or major modification to a major source under the PSD program can be approved:

1. The air quality analysis must determine if the PSD de minimis monitoring levels are triggered, which would require preconstruction ambient air quality monitoring;
2. The air quality analysis must demonstrate that the BACT emission limits from the proposed project added with the background concentrations for each pollutant will not cause a violation of any applicable National Ambient Air Quality Standards (NAAQS); and
3. The BACT emission limits from the proposed project do not exceed any applicable PSD Class I or II increments.

The existing air quality or background concentration is defined by the existing natural and human-generated sources of air pollution. The area surrounding the proposed facility is considered rural and in attainment for all regulated pollutants. Dispersion modeling is intended to provide conservative estimates of ambient air quality concentrations that may potentially result from the proposed project emissions in combination with emissions from existing nearby sources.

7.5.1 Significant Impact Levels (SILs) and De minimis Monitoring Levels

The proposed project triggered a PSD review for particulates, nitrogen oxides, and carbon monoxide. A significant impact analysis was performed to determine whether the proposed project could cause a significant off-site impact; that is, exceed the PSD modeling significant impact levels or de minimis monitoring levels. Only the potential emissions from the project sources are included in the significant impact analysis.
The highest modeled pollutant concentration for each averaging time is compared to the significant impact levels and de minimis monitoring levels. If the highest modeled concentration for any pollutant modeled results in an impact below the significance impact levels for each averaging period, no further modeling for that pollutant is needed to determine compliance with the NAAQS or PSD increments; however, these pollutants may still be subject to further review as part of the PSD additional impact analysis requirements. If the model predicts impacts at or above the modeling significance impact level for any pollutant, a cumulative analysis including all point sources within the radius of impact will be required for that pollutant. If the model predicts impacts at or above the de minimis monitoring levels preconstruction monitoring is required for that pollutant.

A detailed description of DENR's air dispersion modeling analysis has been included as Appendix A. BEPC submitted its own modeling analysis as Appendix D to the PSD permit application. The results of both DENR's and the applicant's analysis showed that ambient air quality impacts from the project will not exceed the PSD significant impact levels or de minimis monitoring levels. Therefore, the Deer Creek generating station project will not cause or contribute to adverse ambient air quality impacts and no further impact analysis is required.

Table 7-14 summarizes the maximum impacts predicted by DENR's and the applicant's modeling, as well as the significant impact level for each pollutant and averaging period.

Table 7-14 – Modeled Impacts and Class II Significant Impact Levels

Pollutant	Averaging Period	DENR's Maximum Modeled Project Impact (ug/m^3)	Applicant's Maximum Modeled Project Impact (ug/m^3)	Significant Impact Level (ug/m^3)	De minimis Monitoring Concentration (ug/m^3)
PM10	24-hour	3.58	3.57	5	10
	Annual	0.126	0.122	1	Not applicable
NO_2	Annual [1]	0.689	0.710	1	14
CO	1-hour	514.6	518.5	2000	Not applicable
	8-hour	233.4	236.3	500	575

[1] – DENR and Applicant modeled nitrogen oxide impacts (a conservative estimate for nitrogen dioxide)

The modeled concentration for the project does not exceed the significant modeling impact levels or de minimis monitoring concentrations for any pollutant or averaging period. No further modeling is required for NAAQS or PSD increment review.

7.5.2 New 1-hour NAAQS for Nitrogen Dioxide

On January 22, 2010, EPA finalized a new short-term (1-hour) nitrogen dioxide (NO_2) ambient standard of 100 parts per billion or 188 micrograms per cubic meter. To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average (8th highest) at each monitor within an area must not exceed the standard. EPA has not yet established significant impact level or de minimis monitoring concentrations for this NAAQS.

DENR used the maximum hourly emission rates for the 1-hour NO_2 modeling analysis (see Appendix A, Table A-5). The emission rates used in the analysis are for all oxides of nitrogen emitted (NOx) while the standard is for NO_2. DENR elected to use this conservative approach because the actual NO_2 portion of the NOx emissions are assumed to be less than 75% of total NOx emissions.

DENR modeled each unit separately to illustrate the impacts of each source, the turbine and inlet air heater to illustrate the impacts of the normal operations, and the impacts of the turbine, inlet air heater, and fire water pump operating simultaneously. Table 7-15 summarizes the modeling results.

Table 7-15 – Modeled 1-hr NOx Impacts (micrograms per cubic meter)

Source	2000 8th highest	2001 8th highest	2002 8th highest	2003 8th daily high	2004 8th daily high	Highest 3-year average
Normal operations [1]	92.0	81.0	77.5	80.5	75.4	84
Fire water pump	85.5	89.0	81.5	83.8	81.9	85
Emergency generator	622.0	624.3	605.0	603.0	597.0	617
Normal operations [1] **with fire water pump**	114.5	118.0	109.0	108.8	104.2	114

[1] – Includes combustion turbine and inlet air heater.

Based on the modeling results DENR will limit the non-emergency operation of the emergency generator to 7 days of operation per calendar year. Because the standard allows seven days where the hourly averages may exceed the standard, the applicable modeling analysis in Table 7-15 above will be the normal operations with fire water pump impacts. Based on these modeled impacts and a measured background NO_2 concentration of 27 microgram per cubic meter as measured in Union County, South Dakota (the most representative monitoring site) the source will not exceed the 188 microgram per cubic meter NO_2 standard.

7.5.3 Other Impacts

BEPC performed an additional impact analysis to assess the potential impact on soils, vegetation, and visibility in the significant impact area caused by the net change in impacts due to the proposed project including industrial, commercial, and residential growth due to the project construction and operation.

7.5.3.1 Commercial, Residential, and Industrial Growth

During the construction phase, (projected to last 2 years) the project may employ as many as 430 workers. Although qualified electricians, pipe fitters, welders, etc., may be available from the Brookings, Watertown, and Sioux Falls areas, some of the skilled workers needed during the construction phase are expected to temporarily relocate from metropolitan areas in the central U.S., including Minneapolis, Minnesota and Omaha, Nebraska.

The presence of temporary workers during the construction phase will likely cause short-term increased demand for goods and services in the area; however, the construction phase is temporary and will not contribute to permanent growth-related emissions.

Following the construction phase, there will be approximately 25 to 30 employees at the Deer Creek generating station. Plant employees will likely be 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 workforce of 430 persons represents approximately 0.18% of the population in the 8-county area. The post-construction employment of 25 to 30 individuals to operate the facility represents approximately 0.011 to 0.013% of the population.

Because most of the permanent positions are expected to be filled with persons living in the area, secondary employment and commercial growth associated with the project (e.g., automotive repair, grocery stores, motels, equipment supply, etc.) will be minimal. The additional permanent jobs are not expected to result in any residential construction or construction-related emissions. 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.

7.5.3.2 Ambient Air Quality Impacts

The ambient air quality analysis consists of determining the air quality in the significant impact area that will exist during the construction and operation of the facility. This analysis involves combining the emissions estimates from the associated growth analysis along with the proposed and existing sources in the area. These projected emissions are then modeled and added to the background air quality in order to estimate the total air quality impact that is likely to occur as a result of the construction and operation of the proposed sources. Construction activities are

expected to be short-lived. No industrial, commercial, or residential growth is expected to occur due to the proposed project. Therefore, the dispersion modeling analysis fulfills the requirement of the ambient air quality impact analysis.

7.5.3.3 Soils and Vegetation

Impact to soils and vegetation in the significant impact area were based on a comparison of the maximum impacts due to the project (high-first-high) to EPA-published thresholds (USEPA 1980). Table 8-8 in the PSD permit application compares the maximum predicted nitrogen dioxide and carbon monoxide impacts to the sensitive vegetation species screening thresholds in EPA's *Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (1980). The maximum predicted impacts for these pollutants are at least an order of magnitude below the sensitive vegetation screening threshold values as given in Table 7-16. As a result, impacts to vegetation in the area due to facility emissions are not expected.

Table 7-16 – Soil and Vegetation Comparison.

Pollutant	Period	Screening [1]	Modeled [2]
Nitrogen Oxides	4-hour	3,760	514
	1-month	564	65
	Annual	94	1
Carbon Monoxide	Weekly	1,800,000	236

[1] – Screening represents EPA's screening threshold concentrations in micrograms per cubic meter

[2] – Modeled represents the modeled predicted concentrations in micrograms per cubic meter.

7.5.3.4 Class I Area Impacts

PSD regulations require that a proposed major source perform an assessment of air quality impacts at Class I areas if these areas are located within 300 kilometers of the proposed facility. Recent federal land manager guidance indicates that all Class I areas within 300 kilometers should be reviewed in the course of a PSD application. There are no Class I areas within 300 kilometers of the proposed facility. Proposed facilities greater than 300 kilometers from a Class I area are not considered a contributor to visibility impairment.

7.5.3.5 Plume Visibility

Visibility impacts were addressed at sensitive Class II areas within 50 kilometers of the project site following guidance in the EPA Workbook for Plume Visual Impact Screening and Analysis (Revised), October 1992, EPA-454/R-92-02, hereafter referred to as Workbook.

The Workbook guidance offers two levels of analysis, a Level 1 screening analysis, and a more refined Level 2 analysis. The Level 1 analysis is the most simplified and conservative approach using default, worst case, meteorological data without considering site-specific conditions. The Level 1 analysis is designed to simulate the most conservative (highest) plume visual impact that an observer may possibly experience. If a Level 1 analysis predicts impacts greater than the

applicable thresholds, a source will perform a more refined Level 2 analysis which takes into account representative meteorological data and site-specific conditions such as complex terrain.

VISCREEN was run in the conservative Level 1 worst case screening mode. The conservative mode uses worst-case meteorological conditions, i.e., extremely stable (F) atmospheric conditions, coupled with a very low wind speed (1 meter/second) persisting for 12 hours, and with a wind direction that would transport the plume directly adjacent to an observer. The plume is considered to be uniformly distributed vertically and normally (Gaussian) distributed horizontally over a 22.5 degree sector in the direction of transport towards the study area. The distance from the emission source to the observer (i.e. located at the sensitive area) is input to the model, along with distances to the closest study area (front and back edge).

The Level 1 screening analysis was performed for the following Class II sites:

- Pipestone National Monument, Minnesota (45 kilometers south-southeast of proposed facility);
- Lake Cochrane, South Dakota (35 kilometers north of proposed facility);
- Lake Poinsett, South Dakota (47 kilometers northwest of proposed facility); and
- Oakwood Lakes, South Dakota (34 kilometers west of proposed facility)

The VISCREEN Level 1 model requires a single nitrogen oxide emission rate and a single particulate matter emission rate. Following EPA guidance, the particulate matter and nitrogen oxide emission rates used in VISCREEN represent the sum of the maximum hourly rates from the four point sources at the proposed site.

VISCREEN nitrogen oxide emission rate input value (99.24 pounds per hour) is the sum of the emission rate from the combustion turbine (65.5 pounds per hour during cold start-up); emergency inlet air heater (2.45 pounds per hour); emergency generator (28.9 pounds per hour); and fire water pump (2.39 pounds per hour).

The particulate matter emission rate input value (24.55 pounds per hour) is the sum of the maximum total (condensable plus filterable) particulate matter emission rates from the combustion turbine (23.2 pounds per hour); inlet air heater (0.19 pounds per hour); emergency generator (0.97 pounds per hour); and fire water pump (0.19 pounds per hour) short-term rates.

The built in VISCREEN default emission rates for primary nitrogen dioxide, soot, and sulfates were used.

VISCREEN requires the average background visible range. Background visual range for the areas of study was set to 40 kilometers as identified in Figure 9, Regional Background Visual Range Values for Use in Level I Visibility Screening, *EPA-454/R-92-023, EPA Workbook for Plume Visual Impact Screening and Analysis (Revised),* October 1992.

VISCREEN also requires source-observer distances and maximum/minimum receptor distances. These distances are listed in Table 7-17.

Table 7-17 – VISCREEN Source-Receptor Distances

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

VISCREEN describes views in terms of the scattering angle (theta), azimuth, and distance from the observer to receptor. Delta E (also known as a color contrast) describes the extent at which the color brightness and contrasts between the emissions and the background will change. 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 delta-E threshold is 2.0, and the contrast threshold is 0.05.

VISCREEN calculates a delta-E and contrast both from inside the study area and outside the study area. In each study area, the maximum impacts occur outside the area looking in. Table 7-18 summarizes DENR's modeled maximum impacts for each area. The impacts modeled by BEPC were nearly identical.

Table 7-18 – Level 1 VISCREEN Result Summary

Maximum Level 1 Impacts Outside Pipestone National Monument					
Background	**Theta (degrees)**	**Azimuth (degrees)**	**Distance (km)**	**Level 1 Delta E**	**Level 1 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
Maximum Level 1 Impacts Outside Lake Cochrane					
Background	**Theta (degrees)**	**Azimuth (degrees)**	**Distance (km)**	**Level 1 Delta E**	**Level 1 Contrast**
Sky	10	35	27.0	1.537	0.004
Sky	140	35	27.0	0.537	-0.011
Terrain	10	0	1.0	1.471	0.015
Terrain	140	0	1.0	0.427	0.015
Maximum Level 1 Impacts Outside Lake Poinsett					
Background	**Theta (degrees)**	**Azimuth (degrees)**	**Distance (km)**	**Level 1 Delta E**	**Level 1 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
Maximum Level 1 Impacts Outside Oakwood Lakes					
Background	**Theta (degrees)**	**Azimuth (degrees)**	**Distance (km)**	**Level 1 Delta E**	**Level 1 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 7-18 illustrates that the modeled impacts are below the Class I thresholds, indicating that the facility will not impact visibility at the Class II sites.

7.6 Operational Restrictions

BEPC's BACT analysis and/or modeling analysis cited specific operational cases. These are required to be included in the permit as operational limitations to validate the BACT analysis and/or modeling analysis. The first permit condition requires BEPC to operate the facility as it is represented in the application, unless otherwise specified in the permit. However, to clarify these operational limitations, the following operational limits will be included in the permit, which is not all inclusive:

1. The generator and fire water pump will utilize ultra low sulfur fuel with a maximum sulfur content of 15 parts per million or 0.0015 percent sulfur;
2. BEPC will be required to install and maintain non-resettable hour meters on the emergency generator and fire water pump; and
3. An acid rain permit application must be submitted 24 months prior to commencing operation of the electrical generating station.

7.7 Compliance Demonstration

There are several methods that may be used to demonstrate compliance with the proposed numerical emission limits such as performance tests and/or continuous emission monitoring. The averaging period, quantity of emissions, and frequency of operation are used to determine the most appropriate compliance demonstration. Table 7-19, identifies the applicable unit and DENR's recommendation of a performance test, continuous emission monitoring system, or design criteria as the compliance demonstration.

Table 7-19 – Compliance Method

Unit	Particulate	Nitrogen Oxide	Carbon Monoxide
#1	Stack Test	CEM [1]	CEM [1]
#2	WPS [2]	WPS [2]	WPS [2]
#3	WPS [2]	WPS [2]	WPS [2]
#4	WPS [2]	WPS [2]	WPS [2]

1 – "CEM" stands for continuous emission monitoring system;
[2] – "WPS" stands for a work practice standard, design standard or surrogate approach used for compliance demonstration.

The August 7, 1980, federal register notice, page 52698, states that an increase of emissions occurs when the unit becomes operational and begins to emit a pollutant. The federal register notice continues to state that "any unit that requires shakedown becomes operational after a

reasonable shakedown period (not to exceed 180 days). Compliance with the emission limits is allowed to occur after a reasonable shakedown period. DENR is requiring BEPC to conduct performance tests to certify the continuous emission monitoring systems and demonstrate compliance. DENR is recommending that the certification of the continuous emission monitoring systems be completed within 60 days of achieving maximum production or within 180 days after initial startup of the facility, whichever comes first.

8.0 Acid Rain Program

As a "new utility unit," the Deer Creek generating station is an affected unit under 40 CFR § 72.6(3) and is subject to the requirements of the Acid Rain Program. In accordance with 40 CFR § 72.30, BEPC must submit an acid rain permit application at least 24 months before the date of initial operation of the Deer Creek generating station.

9.0 State Requirements

9.1 Title V Air Quality Permit

Any source operating in South Dakota that meets the requirements of the Administrative Rules of South Dakota (ARSD) 74:36:05:03 is required to obtain a Title V air quality permit. BEPC's Deer Creek generating station is required to obtain a Title V air quality permit because the potential criteria air pollutant emissions from the proposed Deer Creek generating station are greater than 100 tons per year. In accordance with the ARSD 74:36:05:03.01, BEPC is required to submit an application for a Title V air quality permit within 12 months after the Deer Creek generating station commences operation.

9.2 State Air Emission Standards

South Dakota has established particulate matter, sulfur dioxide, and opacity emission limits in ARSD 74:36:06. In accordance with ARSD 74:36:06:01, the particulate matter and sulfur dioxide emission limits in ARSD 74:36:06 are not applicable if a particulate matter and sulfur dioxide emission limit specified in either ARSD 74:36:07 (NSPS) or ARSD 74:36:09 (PSD) is applicable. BEPC submitted an application for a PSD air quality permit for the Deer Creek generating station. In the PSD application, BEPC proposed particulate matter emission limits for the proposed equipment. In addition, BEPC is required to meet particulate matter and sulfur dioxide limits under NSPS regulations. Therefore, South Dakota's particulate matter and sulfur dioxide emission limits are not applicable.

In accordance with ARSD 74:36:12:01, the Deer Creek generating station is required to maintain visible emissions from the permitted equipment at less than 20 percent opacity.

10.0 Recommendation

Based on the information submitted in the air quality permit application, DENR recommends conditional approval of a PSD construction permit for Basin Electric Power Cooperative's Deer Creek generating station near White, South Dakota. Questions regarding this permit review should be directed to Marlys Heidt, National Resources Project Engineer.

APPENDIX A

AIR QUALITY IMPACT ANALYSIS

1.0 Background Information

The Deer Creek generating station will be located approximately 14 miles northeast of Brookings and 6 miles southeast of White in Brookings County, South Dakota. 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 (UTM) coordinates of the facility are 696,451 meters east and 4,918,630 meters north (UTM zone 14, NAD 27 projection). The terrain around the site is slightly rolling; terrain elevations range from 1,750 feet above mean sea level (AMSL) to 1,860 feet AMSL around the project site. Brookings County is classified as being in attainment or unclassifiable for all National Ambient Air Quality Standards (NAAQS).

2.0 Model Selection

Estimates of ambient concentrations are based upon applicable air quality models, databases and other requirements specified in appendix W of 40 CFR Part 51 (Guideline on Air Quality Models). The current version of the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) was used to estimate impacts for nitrogen dioxide, modeled as total oxides of nitrogen (NOx), carbon monoxide (CO), and particulates. The modeling analysis was conducted using the regulatory default options. Building wake and downwash effects were accounted for using the Building Profile Input Program (BPIP). Current version numbers of the AERMOD model and pre-processors that were used include:

- AERSURFACE version 08009;
- AERMET version 06341;
- AERMAP version 09040;
- BPIP version 04274; and
- AERMOD version 07026.

AERMOD is recommended for use in modeling multi-source emissions and can account for plume downwash, stack tip downwash, and point, area, and volume sources (US EPA 2005, 2004). AERMOD also has the ability to model impacts over both simple (below stack height) and complex (above the height of the stack) terrain.

AERMOD input files will be assembled with the most recent version of Lakes Environmental MS-Windows ISC-AERMOD-View© program. The interface will be used for creating input files, managing AERMOD simulations, and executing the AERMOD codes, including the AERSURFACE, AERMET, AERMAP, and BPIP preprocessors. ISC-AERMOD-View© uses only US EPA FORTRAN executable codes per US EPA guidance concerning the use of FORTRAN executables (US EPA, 2007)

3.0 Model and Pre-Processor Inputs

3.1 AERSURFACE

EPA has developed the AERSURFACE processor to calculate the surface characteristics (Albedo, Bowen Ratio, and surface roughness length) based on land cover data for the study area and output in a format for use in AERMET. AERSURFACE requires the input of digitized land cover data from the U.S. Geological Survey (USGS) National Land Cover Data 1992 archives (NLCD92). AERSURFACE matches the NLCD92 land cover categories to seasonal values of Albedo, Bowen Ratio, and surface roughness. DENR downloaded and used the South Dakota .tif file available at http://edcftp.cr.usgs.gov/pub/data/landcover/states/.

AERSURFACE asks the user to enter the type of coordinates to be used for the center of the study area site. The AERSURFACE users guide states the center of the study area be the location of the surface station meteorological tower (measurement site). AERSURFACE uses these coordinates to extract land cover data for the area of interest from the NLCD92 data file. DENR used the surface station coordinates shown in Table A-2.

Land cover categories in the NLCD92 file are linked within AERSURFACE to a set of seasonal surface characteristics. The values of seasonal surface characteristics by land cover category were developed for the continental U.S. for five seasonal categories. AERSURFACE provides the option of choosing which months belong to which seasonal category for the site-specific climate. DENR used the program's default setting which assigns the months of March, April, and May to seasonal category 5 ("Transitional spring with partial green coverage or short annuals"); June, July, and August to seasonal category 1 ("Midsummer with lush vegetation"); September, October, and November to seasonal category 2 ("Autumn with unharvested cropland"); and December, January, and February to seasonal category 4 ("Winter with continuous snow on ground").

The user is given the option of defining the surface roughness length for multiple sectors, up to a maximum of 12. DENR selected the maximum of 12 sectors for this analysis.

The user must enter a distance of 0.1 to 5.0 kilometers from the center of the site location for use in calculating the effective surface roughness length. AERSURFACE uses this information, along with the coordinates of the center of the study area, to extract a subsection of land cover data from the NLCD92 data file. In the AERMOD Implementation Guide Addendum published January 9, 2008, the recommended upwind distance for processing land cover data to determine the effective surface roughness for input to AERMET is one kilometer relative to the meteorological tower location. Therefore, DENR used a radius of one kilometer in this analysis.

Because the land cover classifications of NLCD92 are applied across the continental U.S., there are instances where the surface characteristic values for two areas of the U.S. may differ, although the land cover type is the same. To address this issue, AERSURFACE asks the user to specify certain characteristics of the meteorological station where the surface data were recorded. The questions and DENR responses for the surface meteorological station are explained below:

- ***"Is this site at an airport?"*** If the site is at an airport, AERSURFACE will use surface characteristics that reflect an area more dominated by transportation land cover. If the user answers "No" to the above question, AERSURFACE will choose higher surface roughness values that are more representative of an area dominated by buildings associated with commercial and industrial land cover. DENR identified the Huron Airport meteorological station as being located at an airport;

- ***"Is this site in an arid region?"*** If the user answers "Yes," AERSURFACE uses the seasonal surface characteristics for the Shrubland and Bare Rock/Sand/Clay categories that are more representative of a desert area. Otherwise, AERSURFACE uses the seasonal surface characteristics for the non-arid area. The Huron meteorological station is located in eastern South Dakota, which is characterized by prairie grasses and farmland and is not an arid region. Therefore, DENR identified the region as non-arid for this analysis;

- ***"Characterize the surface moisture condition at the site relative to climatological normals, to be applied for all periods. Enter 'A' for Average, 'W' for Wet, or 'D' for Dry."*** The answer to this question affects the value of the Bowen ratio. The current version of AERSURFACE applies the user defined surface moisture condition for the entire meteorological data period. Therefore, DENR processed the data year by year, creating 5 separate AERMET files. The surface moisture condition is determined by comparing precipitation for the year of meteorological data to be processed to the 30-year climatological record, selecting "wet" conditions if precipitation is in the upper 30th-percentile, "dry" conditions if precipitation is in the lower 30th-percentile, and "average" conditions if precipitation is in the middle 40th-percentile.

According to the National Climatic Data Center publication, *Climatography of the United States NO. 84, 1971-2000.*, the middle 40th-percentile precipitation for the Huron meteorological station corresponds to annual precipitation of between 17.87 and 23.30 inches. Table A-1 displays the annual precipitation recorded at the site for the corresponding years of meteorological data and surface moisture condition used in processing that year's meteorological data.

Table A-1 – Surface Moisture Condition 2000-2004

Surface Moisture	2000	2001	2002	2003	2004
Actual Precipitation Recorded (inches)	20.08	26.78	14.88	16.42	29.71
Surface Moisture Condition	Average	Wet	Dry	Dry	Wet

- ***"Does the site experience continuous snow cover in the winter months?"*** Because the surface characteristics are affected by snow cover, this question is asked of the user to determine whether surface characteristics for continuous snow cover should be used. The wording of this prompt will vary as shown depending on the temporal resolution for outputs specified by the user. According to the National Climatic Data Center publication of average monthly snow depth recorded at Kennebec, South Dakota (1971-2000), 85 miles southwest of the Huron meteorological station, the area normally has an average monthly snow depth of

1-2 inches during the winter period (December, January, and February). DENR used Kennebec since it was the closest location to the project site that recorded this information. Therefore, DENR selected yes to this question.

3.2 AERMET

EPA developed the AERMET processor as a general purpose meteorological preprocessor for organizing different available meteorological data sets into a format suitable for use in AERMOD. The AERSURFACE output described above, surface meteorological data, and upper air sounding data are input into the AERMET processor.

Surface meteorological data from the National Weather Service station at the Huron Airport for the years 2000-2004 were used by DENR and provided to the applicant for use in this analysis. All years had greater than 95 percent data recovery on an annual basis. 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 so these data are representative of the meteorological conditions experienced at the project site.

The temperature structure of the atmosphere prior to sunrise is required by AERMET to estimate the growth of the convective boundary layer for each day. AERMET uses upper air soundings from the nearest upper air observing station for this purpose. Concurrent 2000-2004 upper air data from the National Weather Service upper air station in Aberdeen, South Dakota, for the years 2000-2004 were used by DENR and provided to the applicant for use in this analysis. The Aberdeen upper-air station is located approximately 120 miles (193 kilometers) northwest of the project location and is considered the closest and most representative upper-air station. Table A-2 lists the details of the meteorological stations used in the modeling.

Table A-2 – Meteorological Station Details

Station	WBAN ID	Degrees Latitude (NAD83)	Degrees Longitude (NAD83)	Elevation (m)	Anemometer Height (m)	Time Zone
Huron Airport Surface Station	14936	44.38	98.22	393	10.0	6
Aberdeen Upper Air Station	14929	45.45	98.42	396	NA	6

The AERMET interface asks the user if the Surface Data is recorded in local standard time. Based on the time and dates listed in the .hus files, DENR selected yes to this question.

The processing carried out by AERMET is somewhat location-dependent. The latitude and longitude entered for the project site are used to calculate the elevation of the sun and the times of sunrise and sunset. The project site is not far enough from either met station to affect these variables; therefore DENR entered the coordinates and elevation of the surface met station for the project site.

3.3 AERMAP

For complex terrain situations, AERMOD captures the essential physics of dispersion in complex terrain and therefore needs elevation data that convey the features of the surrounding terrain. In response to this need, AERMAP searches for the terrain height and location that has the greatest influence on dispersion for each individual receptor. This height is referred to as the hill height scale. Both the base elevation and hill height scale data are produced by AERMAP as a file or files which can be directly inserted into an AERMOD input control file.

The USGS National Elevation Data (NED) in GeoTIFF format can be used directly with the EPA's newly released AERMAP model, dated 09040, and it is the terrain data set recommended for use in the United States for regulatory purposes (Section 4 of the latest revised AERMOD Implementation Guide). DENR downloaded NED data for the region from the USGS Seamless Server at http://seamless.usgs.gov/website/seamless/viewer.htm for input into the AERMAP processor. The data was downloaded in GeoTIFF format and is on file at DENR under R:\Work\AirQuality\Air Regions\Vermillion\Basin - Deer Creek\DENR Modeling files\Terrain\NED_73499051.zip. The analysis included all data necessary to cover the entire receptor grid, plus a buffer of 1.5 kilometers beyond the receptor grid area. The resulting terrain contours, with elevations in meters, are shown in Figure A-1.

3.4 BPIP

The effects of plume downwash were considered for the applicable point sources within the facility fence line. Direction-specific building dimensions were calculated using the current version of the EPA-approved Building Profile Input Program (BPIP). Building dimensions for the proposed equipment and existing facility structures were obtained from the BPIP file (Deer_Creek.pip) submitted by BEPC in May2009. Eleven buildings and/or structures were included in the analysis.

3.5 AERMOD

The AMS/EPA Regulatory Model AERMOD was used to estimate impacts from applicable pollutants. The modeling analysis was conducted using elevated terrain and the regulatory default options for rural areas.

3.6 Ambient Air Boundary and Receptor Grid

DENR's air quality analysis used a nested receptor grid and a fence line which was imported from BEPC's submitted modeling files and then assigned elevations and hill heights based on DENR's AERMAP processing.

The innermost (first) nested grid extended to approximately 800 meters from the fence line in all directions. This grid had a 50-meter spacing. The second grid extended from approximately 800 meters to 2,700 meters from the fence line had a 100-meter spacing. The third grid extended from approximately 2,700 meters to 5,200 meters from the fence line and had a 500-meter receptor spacing. The outermost grid extended from 5,200-10,000 meters from the fence line and

had a 1,000-meter receptor spacing. The resulting grid had 6,285 receptors and is shown in Figure A-2.

4.0 Combustion Turbine Operating Condition Considerations

The combustion turbine is capable of operating at different loads which will have different emission rates and stack exit velocities. This will affect the dispersion characteristics and impacts at these loads.

BEPC performed an air dispersion modeling analysis using various combinations of operating conditions for the combustion turbine based on averaging period (annual and short-term); load condition (25%, 50%, 75% and 100% load) and atmospheric temperature (annual average of 43ºF; winter temperature of -41ºF; and summer temperature of 94ºF). Augmented (duct) firing was also evaluated for the 100% load conditions. Three additional start-up conditions (hot, warm, and cold start-ups) were also modeled, for a total of 20 operating scenarios. DENR modeled the combustion turbine 100% load condition and the load condition that resulted in the highest predicted impacts as part of its analysis (50% load for particulates and 25% load for NOx).

5.0 Significant Impact and Deminimis Monitoring Levels

The proposed project triggered a PSD review for particulates, nitrogen oxides, and carbon monoxide. A significant impact analysis was performed to determine whether the proposed project could cause a significant off-site impact; that is, exceed the PSD modeling significance levels. DENR's modeling review included an analysis of the modeling inputs used by the applicant as well as running the models using DENR's own inputs and process of: terrain elevations (AERMAP), MET data (AERSURFACE and AERMET), and building downwash (BPIP). DENR modeled the combustion turbine 100% load condition and the load condition that resulted in the highest predicted impacts as part of its analysis.

Only the potential emissions from the proposed project are included in the significant impact analysis. If any modeled pollutant results in an impact below the significance level for each averaging period, no further modeling for that pollutant is required to determine compliance with the NAAQS. However, if the model predicts impacts at or above the modeling significance level for any pollutant, a cumulative analysis including all point sources within the radius of impact (ROI) will be required for that pollutant.

Tables A-3 lists the constant stack parameters and emission rates used in each analysis and operating load scenario.

Table A-3 – Constant Modeled Parameters

Source Description	UTM E (m)	UTM N (m)	Temperature (K)	Stack Height (m)	Stack Diameter (m)
Combustion turbine	696451.0	4918630.0	366.48	45.72	5.79
Inlet air heater	696451.0	4918633.0	422.04	9.14	0.47
Emergency generator	696368.7	4918530.5	727.59	4.57	0.43
Fire water pump	696494.0	4918705.4	727.59	9.14	0.18

Because the inlet air heater, emergency generator, and fire water pump will not operate constantly, the hourly emission rates were adjusted for the annual AERMOD modeling runs. The modeled emission rates and exit velocities for each unit, pollutant, firing rate, and applicable averaging period are shown in Table A-4. The exit velocities and emission rates shown for the inlet air heater, emergency generator, and fire water pump do not vary with combustion turbine load.

Table A-4 –Modeled Emission Rates and Exit Velocities

Pollutant	Averaging Period	Combustion Turbine 100% + duct	Combustion Turbine 50%	Combustion Turbine 25%	Inlet Air Heater	Emergency Generator	Fire Water Pump
Exit Velocity (feet/sec)		62.6	40.5	32.3	85.0	135.0	135.0
NOx (lb/hr)	Annual	29.20	NA	9.60	0.0420	0.4949	0.0409
CO (lb/hr)	1 and 8-hrs	57.20	NA	NA	2.060	16.8	3.31
PM 10 (lb/hr)	Annual	22.90	10.90	NA	0.0033	0.0166	0.0033
	24-hr	22.90	10.90	NA	0.1900	0.0808	0.0158

Based on EPA's draft guidance, *New Source Review Workshop Manual,* October 1990, if the maximum modeled impact for the proposed project does not exceed the Class II significant impact levels then EPA does not require any further NAAQS or PSD increment modeling for that pollutant. Table A-5 displays a comparison of DENR's maximum modeled concentrations from the onsite sources to the significant impact levels.

Table A-5 – Modeled Impacts and Class II Significant Impact Levels

Pollutant	Averaging Period	100% + duct Project Impact (ug/m^3)	50% + duct Project Impact (ug/m^3)	25% + duct Project Impact (ug/m^3)	Significant Impact Level (ug/m^3)	De minimis Monitoring Concentration (ug/m^3)
PM 10	24-hour	3.58	3.58	NA	5	10
	Annual	0.126	0.100	NA	1	NA
NO_2	Annual[1]	0.686	NA	0.689	1	14
CO	1-hour	514.6	NA	NA	2000	NA
	8-hour	233.4	NA	NA	500	575

[1] – DENR modeled NOx impacts (a conservative estimate for NO_2)

The modeled concentrations for the project do not exceed the significant modeling impact levels or de minimis monitoring concentrations for any pollutant or averaging period. Therefore, no further modeling is required for NAAQS or PSD increment review for these pollutants and averaging periods.

6.0 New NAAQS for Nitrogen Dioxide

EPA recently finalized a new short-term (1-hour) nitrogen dioxide (NO_2) ambient standard of 100 parts per billion or 188 micrograms per cubic meter. To attain this standard, the 3-year average of the 98th percentile (8th highest) of the daily maximum 1-hour average at each monitor within an area must not exceed the standard.

EPA has not yet established a significant impact level or de minimis monitoring concentration for this NAAQS.

DENR used the maximum hourly emission rates for the 1-hr NOx modeling analysis. The modeled 1-hr emission rates, based on the permit application, for each unit and applicable averaging period are shown in Table A-5.

Table A-5 – 1-hr NOx Modeled Emission Rates

Pollutant	Averaging Period	Combustion Turbine 100% + duct	Inlet Air Heater	Emergency Generator	Fire Water Pump
NOx (lb/hr)	1-hr	65.5	1.2	28.9	2.39

Figure A-1 – Terrain Contours

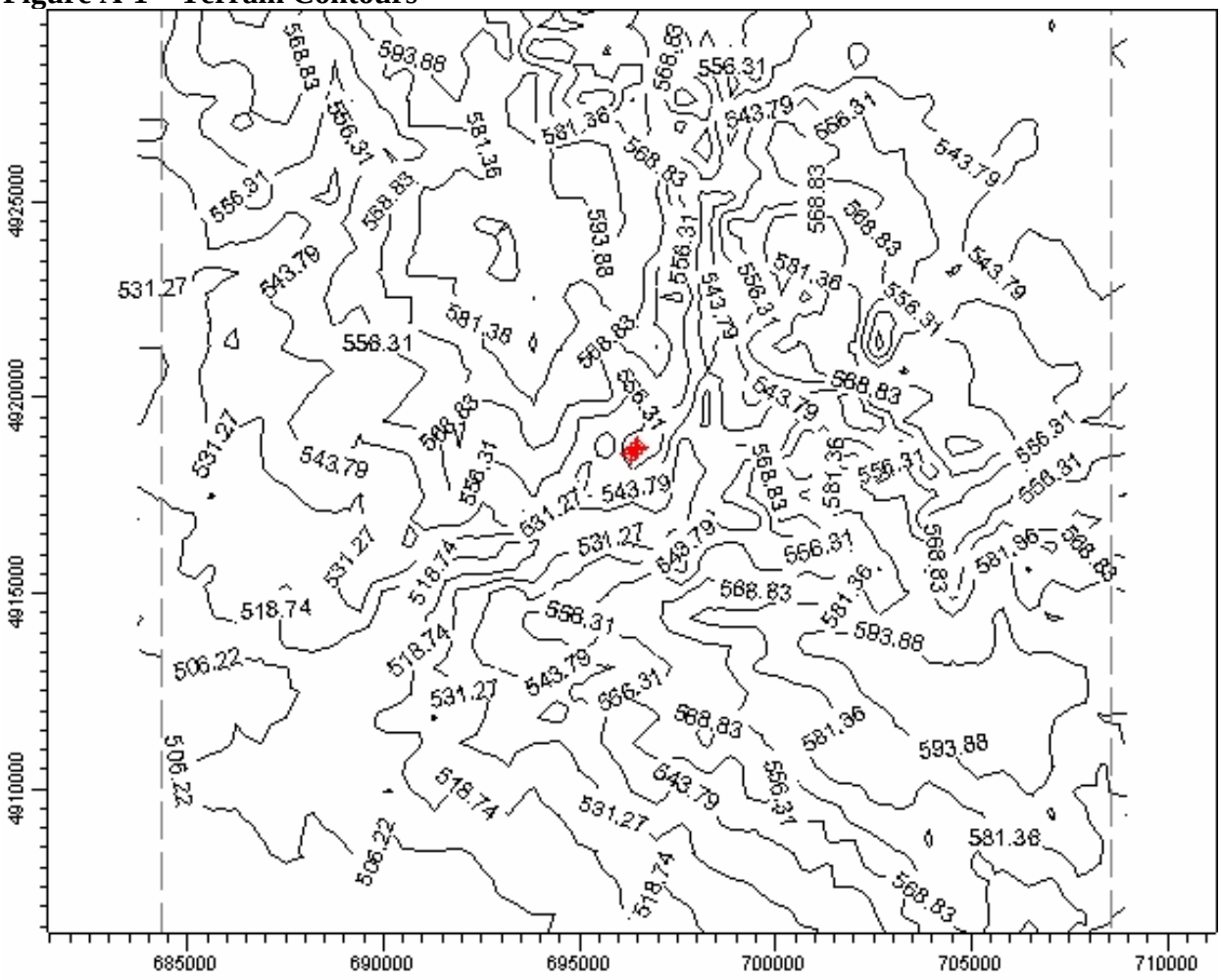
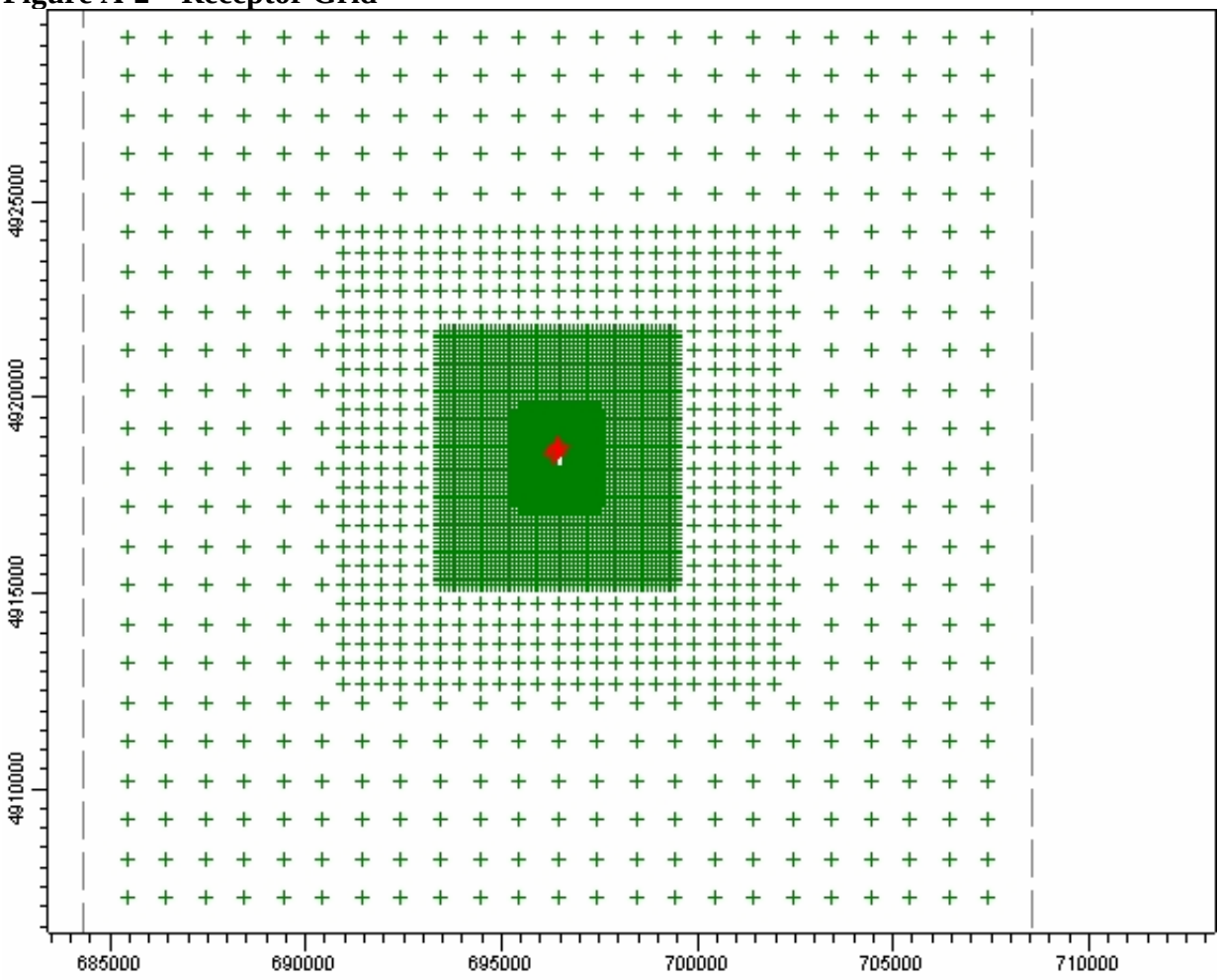
Figure A-2 – Receptor Grid