DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

Permit Application Analysis
A0000634

September 17, 2015

NAME OF FIRM:	Black Hills Power, Inc. and Cheyenne Light Fuel & Power
NAME OF FACILITY:	Cheyenne Generating Station
FACILITY LOCATION:	Southeast of Cheyenne, Wyoming Near I-80 Campstool Road Exit Laramie County, Wyoming 523,500 m E; 4,552,500 m N (UTM Zone 13, NAD 83)
TYPE OF OPERATION:	Natural Gas Fired Electric Generation
RESPONSIBLE OFFICIAL:	Mark L. Lux
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1.0 PURPOSE OF APPLICATION

Black Hills Power, Inc. submitted an application to modify the Cheyenne Prairie Generating Station (CPGS) by converting two of the permitted simple cycle turbines into a combined cycle configuration. The combined cycle turbines will consist of either GE LM6000 PF or GE LM6000 PF+ turbines. The use of the PF+ turbines will boost the facility from a nominal 220 megawatt (MW) output to a nominal 240 MW output.

For the proposed modification the following changes will be made:

• Reconfigure two simple cycle turbines to combined cycle turbines;
• Addition of a wet cooling tower for heat rejection from the combined cycle unit;
• Addition of an auxiliary boiler to preheat the heat recovery system generator (HRSG) of the combine cycle unit;
• Elimination of one of the six gas-fired turbine inlet air heaters;
• Elimination of three inlet air chillers; and
• Elimination of two gas-fired fuel gas heaters.

2.0 PROCESS DESCRIPTION

2.1 Simple Cycle Combustion Turbines

After the proposed modification, the CPGS will use one (1) GE LM6000 40 MW combustion turbine operated in simple cycle mode without heat recovery. This turbine (EGU003), which has been installed, is fired on pipeline quality natural gas. The combustion turbine consists of a compressor, combustor, and expansion turbine. After filtration, air passes through the compressor before combining with the fuel and entering the combustor. The combustion products and compressed air pass through the expansion turbine, which drives both the compressor and the generator.

2.2 Combined Cycle Combustion Turbines

The CPGS currently utilizes two (2) GE LM6000 MW combustion turbines (EGU001 and EGU002) in a combine-cycle configuration. The proposed modification will convert two permitted simple cycle combustion turbines (not installed) into a combined cycle configuration. These turbines may consist of GE LM6000 40 MW or GE LM6000 PF+ 45 MW combustion turbines. The combine cycle turbines operate in a 2x1 combined cycle design with two combustion turbine generators and one steam turbine. The combined cycle turbines operate in the same fashion as the simple cycle turbines except that the turbines will be equipped with unfired (no duct burners) heat recovery steam generators (HRSGs) to extract heat from each turbine exhaust to make steam. The produced steam will be used in the steam turbine to produce more electricity.

2.3 Wet Cooling Tower

Wet cooling towers will be used to provide cooling to condense the steam that is exhausted from the steam turbines in order to increase system efficiency. The steam condensers will have circulating cooling water flow through tubes that will absorb the heat from the condensing steam that is exhausted from the steam turbine. The warm circulating water is then pumped to the cooling tower where it flows down through the tower and is cooled through evaporation. The cooled circulating water then flows back to the steam condensers to pick up more heat.

2.4 Inlet Air Heaters

Inlet air heaters will be installed at the compressor inlet of each combustion turbine generator, upstream of the inlet air filter. The inlet air heating system raises the temperature of the ambient air entering the combustion turbine generators during periods of low ambient air temperature to prevent icing for safety reasons and will bring the inlet temperature within a specific range to ensure vendor emission guarantees.

2.5 Diesel Fire Pump

A diesel fire pump engine is used to provide fire protection water for the plant. The engine utilizes ultra-low sulfur diesel fuel, and operates only during testing. Total operating hours for the fire pump are 250 hours per year or less.

2.6 Emergency Generator

A diesel emergency generator is used to provide emergency power for the plant. This engine utilizes ultra-low sulfur diesel fuel, and normally operates during testing. Total operating hours for the emergency generator are 500 hours per year or less.

2.8 Storage Tanks

Storage tanks will be utilized at the CPGS to store diesel fuel for the fire water pump and emergency generator, aqueous ammonia for the selective catalytic reduction (SCR) systems, and several water storage tanks.

3.0 ESTIMATED EMISSIONS

Existing permitted emissions for the CPGS are shown in Table 3-1. Emissions for the CPGS after the proposed modification are shown in Table 3-2. Emissions in Table 3-2 are based on the proposed best available control technology (BACT) limits for the facility.

Table 3-1: Cheyenne Prairie Generating Station Emissions (tpy) [1]											
ID	Description	NO_x	CO	SO_2	PM	PM_{10}	$PM_{2.5}$	VOC	HAPs	Ammonia	CO_2e
Existing (CT-12636 & MD-16173)											
EP01	CT01A CCCT	25.5	32.0	2.1	17.5	17.5	17.5	14.7	0.3	24.9	187,318
EP02	CT01B CCCT	25.5	32.0	2.1	17.5	17.5	17.5	14.7	0.3	24.9	187,318
EP03	CT02A SCCT	36.0	32.9	2.1	17.5	17.5	17.5	14.0	0.3	24.9	187,318
EP04	CT02B SCCT	36.0	32.9	2.1	17.5	17.5	17.5	14.0	0.3	24.9	187,318
EP05	CT03A SCCT	36.0	32.9	2.1	17.5	17.5	17.5	14.0	0.3	24.9	187,318
EP06	Inlet Air Heater 01 [2]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
EP07	Inlet Air Heater 02 [2]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
EP08	Inlet Air Heater 03 [2]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
EP09	Inlet Air Heater 04 [2]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
EP10	Inlet Air Heater 05 [2]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
EP11	Inlet Air Heater 06 [2]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
EP12	Inlet Air Chiller 01 [3]	--	--	--	<0.1	<0.1	<0.1	--	--	--	--
EP13	Inlet Air Chiller 02 [3]	--	--	--	<0.1	<0.1	<0.1	--	--	--	--
EP14	Inlet Air Chiller 03 [3]	--	--	--	<0.1	<0.1	<0.1	--	--	--	--
EP15	Diesel Generator [4]	2.7	0.2	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	--	226
EP16	Diesel Fire Pump [5]	0.2	0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	--	51
EP17	Cooling Tower	--	--	--	7.3	5.5	5.5	--	--	--	--
EP18	Fuel Gas Heater 01 [2]	2.3	1.4	<0.1	0.1	0.1	0.1	0.1	<0.1	--	1,153
EP19	Fuel Gas Heater 02 [2]	2.3	1.4	<0.1	0.1	0.1	0.1	0.1	<0.1	--	1,153
EP20	Auxiliary Boiler	1.9	4.1	0.1	1.9	1.9	1.9	0.2	0.2	--	12,855
Facility Total		**170.8**	**186.1**	**10.7**	**98.7**	**96.9**	**96.9**	**73.0**	**1.8**	**124.5**	**976,730**

[1] Emission estimates include startup and shutdown emissions.
[2] Emissions are based on 4,380 hours of operation per year.
[3] Emissions are based on 5,330 hours of operation per year.
[4] Emissions are based on 500 hours of operation per year.
[5] Emissions are based on 250 hours of operation per year.
CCCT = Combine Cycle Combustion Turbine
SCCT = Simple Cycle Combustion Turbine

Table 3-2: Cheyenne Prairie Generating Station Emissions (tpy) [1]

IMPACT ID	ID	Description	NO_x	CO	SO_2	PM	PM_{10}	$PM_{2.5}$	VOC	HAPs	Ammonia	CO_2e
Proposed												
EGU001	EP01	CT01A CCCT	25.5	32.0	2.1	17.5	17.5	17.5	14.7	0.3	24.9	187,318
EGU002	EP02	CT01B CCCT	25.5	32.0	2.1	17.5	17.5	17.5	14.7	0.3	24.9	187,318
EGU003	EP03	CT02 SCCT	36.0	32.9	2.1	17.5	17.5	17.5	14.0	0.3	24.9	187,318
EGU004	EP04	CT03A CCCT [2,3]	28.7	31.7	2.6	17.5	17.5	17.5	16.0	0.3	28.4	220,234
EGU005	EP05	CT03B CCCT [2,3]	28.7	31.7	2.6	17.5	17.5	17.5	16.0	0.3	28.4	220,234
HET003	EP06	Inlet Air Heater 01 [4]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
HET004	EP07	Inlet Air Heater 02 [4]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
HET005	EP08	Inlet Air Heater 03 [4]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
HET006	EP09	Inlet Air Heater 04 [4]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
HET007	EP10	Inlet Air Heater 05 [4]	0.4	2.7	<0.1	0.3	0.3	0.3	0.2	0.1	--	4,117
CTW010	EP11	Cooling Tower	--	--	--	7.3	5.5	5.5	--	--	--	--
CTW016	EP12	Cooling Tower	--	--	--	8.4	6.4	6.4	--	--	--	--
BOL007	EP13	Auxiliary Boiler	1.9	4.1	0.1	1.9	1.9	1.9	0.2	0.2	--	12,855
BOL008	EP14	Auxiliary Boiler	1.9	4.1	0.1	1.9	1.9	1.9	0.2	0.2	--	12,658
ENG001	EP15	Diesel Generator [5]	2.7	0.2	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	--	226
ENG002	EP16	Diesel Fire Pump [6]	0.2	0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	--	51
	Facility Total		**153.1**	**182.3**	**11.7**	**108.5**	**104.7**	**104.7**	**76.8**	**2.4**	**131.5**	**1,048,797**

[1] Emission estimates include startup and shutdown emissions.
[2] Unit may consist of a GE LM6000 40 MW or GE LM6000 PF+
[3] Emissions are based on the installation of a GE LM6000 PF+
[4] Emissions are based on 4,380 hours of operation per year.
[5] Emissions are based on 500 hours of operation per year.
[6] Emissions are based on 250 hours of operation per year.
CCCT = Combine Cycle Combustion Turbine
SCCT = Simple Cycle Combustion Turbine

4.0 CHAPTER 6, SECTION 4 – PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

The CPGS is a major stationary source under Chapter 6, Section 4 of the Wyoming Air Quality Standards and Regulations (WAQSR), as the facility is a named source (fossil fuel-fired steam electric plant of more than two hundred and fifty million British thermal units per hour heat input) which emits or has the potential to emit one hundred tons per year or more. The proposed permitting action is not subject to Prevention of Significant Deterioration (PSD) review under Chapter 6, Section 4 of the WAQSR as a physical change in or change in the method of operation at the facility does not result in a significant emission increase of a NSR regulated pollutant, and a significant net emissions increase of that pollutant. The applicability for the CPGS is described and shown in Tables 4-1, 4-2, and 4-3.

Table 4-1: Project Potential Emissions (tpy)

IMPACT ID	Description	NO_x	CO	SO_2	PM	$PM_{10}/PM_{2.5}$	VOC
New/Modified Sources							
EGU004	CT03A CCCT	28.7	31.7	2.6	17.5	17.5	16.0
EGU005	CT03B CCCT	28.7	31.7	2.6	17.5	17.5	16.0
CTW016	Cooling Tower	--	--	--	8.4	6.4	--
BOL008	Auxiliary Boiler	1.9	4.1	0.1	1.9	1.9	0.2
Total Project Emissions		**59.3**	**67.5**	**5.3**	**43.3**	**43.3**	**32.2**

For existing emission units; the actual emissions in Table 4-2 are the potential emissions. This is due to the fact that these units have not resumed normal operation under the previous permit which affected these units (MD-12636).

Table 4-2: Baseline Actual Emissions (tpy)

IMPACT ID	Description	NO_x	CO	SO_2	PM	$PM_{10}/PM_{2.5}$	VOC
New/Modified Sources							
EGU004	CT03A CCCT	28.7	31.7	2.6	17.5	17.5	16.0
EGU005	CT03B CCCT	28.7	31.7	2.6	17.5	17.5	16.0
Total Project Emissions		**57.4**	**63.4**	**5.2**	**35.0**	**35.0**	**32.0**

Table 4-3: PSD Applicability

NSR Pollutant	Project Emissions	Baseline Actual Emissions	Contemporaneous Emission Change	**Net Emissions Change**	PSD Significant Emission Rates	**PSD Review Required**
NO_x/Ozone/$PM_{2.5}$	59.3	57.4	--	**1.9**	40	**No**
CO	67.5	63.4	--	**4.1**	100	**No**
$SO_2/PM_{2.5}$	5.3	5.2	--	**0.1**	40	**No**
PM	43.3	35.0	--	**8.3**	25	**No**
$PM_{10}/PM_{2.5}$	43.3	35.0	--	**8.3**	15/10	**No**
VOC	32.2	32.0	--	**0.2**	40	**No**

Based on the net emissions change (as shown in Table 4-3), the proposed modification at the CPGS is not subject to PSD requirements as the net emissions change for each NSR regulated pollutant is less than the significant emission rate as defined in Chapter 6, Section 4 of the WAQSR.

5.0 CHAPTER 6, SECTION 3 – MAJOR SOURCE APPLICABILITY (TITLE V)

The CPGS is a "major source" as defined by Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations (WAQSR). Black Hills Power, Inc. will be required to obtain an Operating Permit per the requirements of Chapter 6, Section 3 of the WAQSR.

6.0 CHAPTER 6, SECTION 2 – BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Per the requirements of Chapter 6, Section 2 of the WAQSR, all facilities must demonstrate the use of BACT. Therefore, Black Hills Power, Inc. conducted a BACT analysis for the control of pollutants in accordance with the WAQSR.

6.1 Turbines (GE LM6000 and LM6000 PF+)

6.1.1 NO_x Emissions

6.1.1.1 Normal Operation

Control Options

Black Hills Power, Inc. identified the following applicable control technologies for reducing NO_x emissions from the combined and simple cycle turbines at the CPGS:

Water Injection
Steam Injection
Dry Low NO_x (DLN) burners
Catalytic Combustion (XONON)
Selective Catalytic Reduction (SCR)
Selective Non-catalytic Reduction (SNCR)
Non-selective Catalytic Reduction (NSCR)
$SCONO_x$

Water and steam injection or wet combustion controls are techniques used to lower the flame temperature in the combustor, and reduce thermal NO_x formation.

DLN burners utilize lean, premixed combustion to keep peak combustion temperatures low, thereby reducing the flame temperature and reducing thermal NO_x formation.

Catalytic combustion is a control technology that uses a catalyst inside the combustor where the air/fuel mixture passes through the catalyst as combustion occurs at lower temperatures compared to standard combustors.

Selective Catalytic Reduction (SCR) is a post-combustion NO_x control technology that can be used on combustion turbines. SCR reduces NO_x emissions by injecting ammonia into the exhaust gas stream upstream of a catalyst. The ammonia reacts with NO_x on the catalyst to form molecular nitrogen and water vapor. For the SCR system to operate properly, the exhaust gas must be within a temperature range of 450 to 850 °F.

Selective non-catalytic reduction (SNCR) reduces NO_x emissions by injection of ammonia or urea into the turbine combustor. SNCR is similar to SCR in that both systems use ammonia to react with nitrogen; however, SNCR operates at higher temperatures than SCR and does not use catalyst. The effective temperature range for SNCR is 1600 to 2200 °F.

Non-selective catalytic reduction (NSCR) utilizes a catalyst without injected reagents to reduce NO_x emissions in an exhaust gas stream. NSCR is only effective in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen. This control is typically utilized in automobile exhaust and stationary rich-burn internal combustion engines.

$SCONO_x$ is a control technology that utilizes a single catalyst for the reduction of NO_x, CO, and VOCs and does not require a reagent such as ammonia. The $SCONO_x$ catalyst functions by oxidizing NO to NO_2. The NO_2 is then absorbed on the surface of the catalyst through the use of a potassium carbonate coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates.

<u>Eliminate Technically Infeasible Options</u>

Black Hills Power, Inc. eliminated wet combustion controls as the turbines will be equipped with DLN burners, which will achieve a comparable emission rate.

Catalytic combustion was eliminated from consideration as this technology is not commercially available for large turbines such as those proposed for the CPGS.

Selective non-catalytic reduction (SNCR) was eliminated from consideration at the exhaust temperatures of the turbines will be less than what is necessary for this control technology.

Non-selective catalytic reduction (NSCR) was eliminated from consideration as the oxygen concentration in the exhaust gases are outside the range necessary for this technology to work effectively.

$SCONO_x$ technology was eliminated as being technically infeasible as this technology has not been applied and demonstrated on large-scale turbines such as those proposed for the CPGS.

<u>Rank Remaining Technologies</u>

The remaining NO_x control technologies for the combined and simple cycle combustion turbines in order of effectiveness are SCR and DLN burners.

<u>Evaluate Remaining Technologies/Select BACT</u>

Black Hills Power, Inc. selected the top control technology for BACT (SCR); therefore, further evaluation of DLN was not warranted. Black Hills Power, Inc. evaluated a range of NO_x emission rates for the combined cycle turbines utilizing SCR. The range of NO_x emission rates evaluated and associated economic impacts for the combined cycle turbines are shown in Table 6-1.

Table 6-1: Comparison of NO_x Control for the Combined Cycle Turbines

Control	Uncontrolled	SCR	SCR	SCR
GE LM6000 PF				
Control Level (ppm[1])	25	3.0	2.5	2.0
Capital Cost ($)	0	1,095,700	1,114,900	1,146,000
Total Annualized Cost ($)	0	452,300	469,700	475,800
Baseline Emission Rate (tpy)	156.5	156.5	156.5	156.5
Controlled Emission Rate (tpy)	156.5	18.8	15.7	12.5
Emission Reduction (tpy)	0	137.7	140.8	144.0
Cost Effectiveness ($/ton)	--	3,285	3,336	3,304
Incremental Cost ($)	--	452,300	17,400	6,100
Incremental Reduction (tpy)		137.7	3.1	3.2
Incremental Cost Effectiveness ($/ton)	--	3,285	5,612	1,906
GE LM6000 PF+				
Control Level (ppm[1])	25	3.0	2.5	2.0
Capital Cost ($)	0	1,104,221	1,126,620	1,181,318
Total Annualized Cost ($)	0	463,962	482,491	492,488
Baseline Emission Rate (tpy)	178.9	178.9	178.9	178.9
Controlled Emission Rate (tpy)	178.9	21.5	17.9	14.3
Emission Reduction (tpy)	0	157.4	161.0	164.6
Cost Effectiveness ($/ton)	--	2,948	2,997	2,992
Incremental Cost ($)	--	463,962	18,529	9,997
Incremental Reduction (tpy)		157.4	3.6	3.6
Incremental Cost Effectiveness ($/ton)	--	2,948	5,147	2,777

[1] ppm level based on 15% O_2.

Black Hills Power, Inc. reported that the most stringent NO_x emission levels from recently permitted projects ranged from 2.5 to 3 ppm_{vd} for GE LM6000 turbines operating in combined cycle mode. Black Hills Power, Inc. noted that they previously permitted GE LM6000 turbines designed for combined cycle operation at the CPGS with a NO_x emission rate of 3 ppm_{vd} at 15% O_2 (1-hr average). Based on the cost analysis and technical concerns with lower emission rates, Black Hills Corporation has proposed a NO_x emission rate of 3 ppm_{vd} at 15% O_2 (1-hr average) for the combined cycle turbines.

The Division reviewed EPA's RBLC database to compare previously permitted NO_x emission rates for similar sources in other states against Black Hills Power, Incorporated's proposed NO_x emission rates. The Division used process code 15.210 when searching the RBLC database. This code refers to combined cycle turbines greater than 25 megawatts utilizing natural gas. Table 6-2 shows the permitted emission rates for a few of the recently permitted emission units identified in the RBLC.

Table 6-2: RBLC Sources Identified for NO_x Emission Limits					
NO_x Emission Rate (ppm_{vd} at 15% O_2)	Averaging Period	Unit	Permit Date	Company/Site	RBLC ID
Results Under Process Code 15.210 (Combined Cycle)					
2**	24-hr rolling average	210 MW	6/18/2015	Eagle Mountain Power – Eagle Mountain Steam Electric Station	TX-0751
2	24-hr rolling average	1100 MW	4/1/2015	Colorado Bend II Power – Colorado Bend Energy Center	TX-0730
2	24-hr rolling average	240 MW	12/19/2014	NRG Texas Power – S R Bertron Electric Generating Station	TX-0714
8 lb/hr	4-hr rolling average	100 MW	12/11/2014	Black Hills Power – Pueblo Generating Station	CO-0076
2	24-hr rolling	197 MW	12/1/2014	Victoria WLE – Victoria Power Station	TX-0710
2	not specified	2159 MMbtu/hr	11/21/14	Moundsville Power, LLC – Moundsville Combined Cycle Power Plant	WV-0025

** Identified as "LAER" (Lowest Achievable Emission Rate) in the RBLC.

Based on the units identified in the RBLC, the Division requested that Black Hills Power, Inc. provide additional information in order to better understand the turbines being proposed against those which have been permitted in other states. Black Hills Power, Inc. identified the turbines listed in the table above as being GE Frame 7 units which are designed for higher efficiencies and base-load operation as compared to the proposed GE LM6000 turbines. The GE Frame 7 units emit approximately 9 ppm NO_x out of the turbine without any add on controls whereas the GE LM6000 PF and PF+ turbines emit 25 ppm NO_x without add on controls. Black Hills Power, Inc. also noted that a 2 ppm NO_x emission rate for the units listed in the table was appropriate because the units were permitted as base load units and have a longer averaging period of 24 hours. The GE LM6000 PF and PF+ turbines are being proposed at 3 ppm (1-hr concentration limit).

The Division considers the cost to control NO_x for all of the ppm values evaluated (3, 2.5, and 2) by Black Hills Power, Inc. to be economically reasonable for the combined cycle turbines. In addition, the incremental cost between the respective ppm levels is also economically reasonable. Based on the Division's review of the RBLC, a 2 ppm NO_x limit has been determined to be representative of BACT by other permitting agencies for larger turbines in a base-load configuration. That being said, the 2 ppm level identified in the RBLC was determined to be BACT for larger turbines with a longer averaging period. Given the size of the proposed GE LM6000 turbines and the proposed averaging period (1-hr) the Division will consider 3 ppm_{vd} @ 15% O_2 as being representative of BACT for NO_x.

6.1.1.1 NO_x Startup/Shutdown

Black Hills Power, Inc. estimated that NO_x emissions would be higher during periods of startup for the combined cycle turbines as the SCR catalyst would not be at the appropriate temperature for emission control. Black Hills Power, Inc. has estimated that the NO_x emission rate would be approximately 22.5 lb/hr for the GE LM6000 PF turbines and would be approximately 23.9 lb/hr for the GE LM6000 PF+ turbines. These emission estimates are based on one startup/shutdown event in an hour for the combined cycle turbines. The Division will establish an hourly emission rate for NO_x emissions from the turbines during periods of startup/shutdown and will limit the combined number of hours of startup/shutdown for the combined cycle turbines to 1200 hours for EGU004 and EGU005.

6.1.2 CO Emissions

6.1.2.1 Normal Operation

Black Hills Power, Inc. identified the following applicable control technologies for reducing CO emissions from the combined and simple cycle turbines at the CPGS:

Catalytic Oxidation
Catalytic Combustion (XONON)
Dry Low NO_x (DLN) burners
$SCONO_x$

Catalytic oxidation is a post combustion control technology that utilizes a catalyst to oxidize CO to CO_2.

Catalytic combustion is a control technology that uses a catalyst inside the combustor where the air/fuel mixture passes through the catalyst as combustion occurs at lower temperatures compared to standard combustors.

DLN burners are incorporated into the design on the proposed turbines (LM6000 combustion turbines) at the CPGS and would represent good combustion practices.

$SCONO_x$ utilizes a single catalyst for the reduction of NO_x, CO, and VOCs and does not require a reagent such as ammonia. $SCONO_x$ combustion functions by oxidizing CO to CO_2.

<u>Eliminate Technically Infeasible Options</u>

Catalytic combustion was eliminated from consideration as this technology is not commercially available for large turbines such as those proposed for the CPGS.

$SCONO_x$ technology was eliminated as being technically infeasible as this technology has not been applied and demonstrated on large-scale turbines such as those proposed for the CPGS.

<u>Rank Remaining Technologies</u>

The remaining CO control technologies for the turbines in order of control effectiveness are an oxidation catalyst and DLN burners (good combustion practices).

Evaluate Remaining Technologies/Select BACT

Black Hills Power, Inc. selected the top control technology for BACT (oxidation catalyst); therefore, further evaluation of DLN was not warranted. Black Hills Power, Inc. evaluated a range of CO emission rates for the combined cycle turbines utilizing catalytic oxidation. The range of CO emission rates evaluated and associated economic impacts for the combined and simple cycle turbines are shown in Table 6-3.

Table 6-3: Comparison of CO Control for the Combined Cycle Turbines

Control	Uncontrolled	CatOx	CatOx	CatOx
GE LM6000 PF				
Control Level (ppm[1])	70	4	3	2
Capital Cost ($)	0	247,700	254,600	270,900
Total Annualized Cost ($)	0	279,200	280,200	282,400
Baseline Emission Rate (tpy)	266.8	266.8	266.8	266.8
Controlled Emission Rate (tpy)	266.8	15.2	11.4	7.6
Emission Reduction (tpy)	0	251.6	255.4	259.2
Cost Effectiveness ($/ton)	--	1,110	1,097	1,090
Incremental Cost ($)	--	279,200	1,000	2,200
Incremental Reduction (tpy)	--	251.6	3.8	3.8
Incremental Cost Effectiveness ($/ton)	--	1,110	263	579
GE LM6000 PF+				
Control Level (ppm[1])	25	4	3	2
Capital Cost ($)	0	348,480	370,260	386,595
Total Annualized Cost ($)	0	293,240	296,274	298,550
Baseline Emission Rate (tpy)	108.9	108.9	108.9	108.9
Controlled Emission Rate (tpy)	108.9	17.4	13.1	8.7
Emission Reduction (tpy)	0	91.5	95.8	100.2
Cost Effectiveness ($/ton)	--	3,205	3,093	2,980
Incremental Cost ($)	--	293,240	3,034	2,276
Incremental Reduction (tpy)	--	91.5	4.3	8.2
Incremental Cost Effectiveness ($/ton)	--	3,205	706	517

[1] Levels are based on 15 percent (15%) oxygen on a 1-hour basis.

Black Hills Power, Inc. reported that the most stringent CO emission level from previously permitted projects was 4 ppm_{vd} for GE LM6000 turbines operating in combined cycle mode. Based on the cost analysis and technical concerns with lower emission rates, Black Hills Power, Inc. has proposed a CO emission rate of 4 ppm_{vd} at 15% O_2 (1-hr average) for the combined cycle turbines.

The Division reviewed EPA's RBLC database to compare previously permitted CO emission rates for similar sources in other states against Black Hills Power, Incorporated's proposed CO emission rate. The Division used process code 15.210 when searching the RBLC database. This code refers to combine cycle turbines greater than 25 megawatts utilizing natural gas. Table 6-4 shows the permitted emission rates for a few of the recently permitted emission units identified in the RBLC.

Table 6-4: RBLC Sources Identified for CO Emission Limits

CO Emission Rate (ppm_{vd} at 15% O_2)	Averaging Period	Unit	Permit Date	Company/Site	RBLC ID
Results Under Process Code 15.210 (Combined Cycle)					
2**	24-hr rolling average	210 MW	6/18/2015	Eagle Mountain Power – Eagle Mountain Steam Electric Station	TX-0751
4	3-hr average	1100 MW	4/1/2015	Colorado Bend II Power – Colorado Bend Energy Center	TX-0730
15	not specified	187 MW	3/31/2015	NRG Texas Power – Cedar Bayou Electric Generating Station	TX-0727
4 (2)	1-hr rolling (12-month rolling)	240 MW	12/19/2014	NRG Texas Power – S R Bertron Electric Generating Station	TX-0714
38 lb/hr	4-hr rolling average	100 MW	12/11/2014	Black Hills Power – Pueblo Generating Station	CO-0076
4	3-hr rolling	197 MW	12/1/2014	Victoria WLE – Victoria Power Station	TX-0710
2	not specified	2159 MMbtu/hr	11/21/14	Moundsville Power, LLC – Moundsville Combined Cycle Power Plant	WV-0025

** Identified as "LAER" (Lowest Achievable Emission Rate) in the RBLC.

Based on the units identified in the RBLC, the Division requested that Black Hills Power, Inc. provide additional information in order to better understand the turbines being proposed against those which have been permitted in other states. Black Hills Power, Inc. identified the turbines listed in the table above as being GE Frame 7 units which are designed for higher efficiencies and base-load operation as compared to the proposed GE LM6000 turbines. The GE Frame 7 units emit approximately 9 ppm CO out of the turbine without any add on controls whereas the GE LM6000 PF and PF+ turbines emit 25 (PF) and 70 (PF+) ppm CO without add on controls. The GE LM6000 PF and PF+ turbines are being proposed at 4 ppm (1-hr concentration limit).

The Division considers the cost to control CO for all of the ppm values evaluated (4, 3, and 2) by Black Hills Power, Inc. to be economically reasonable for the combined cycle turbines. In addition, the incremental cost between the respective ppm levels is also economically reasonable. Based on the Division's review of the RBLC, a 4 ppm CO limit has been determined to be representative of BACT by other permitting agencies for larger turbines in a base-load configuration. Given the size of the proposed GE LM6000 turbines and the proposed averaging period (1-hr) the Division will consider 4 ppm_{vd} @ 15% O_2 as being representative of BACT for CO.

6.1.2.2 Startup/Shutdown

Black Hills Power, Inc. estimated that CO emissions would be higher during periods of startup for the combined cycle turbines as the SCR catalyst would not be at the appropriate temperature for emission control. Black Hills Power, Inc. has estimated that the CO emission rate would be approximately 56.5 lb/hr for the GE LM6000 PF turbines and would be approximately 47.8 lb/hr for the GE LM6000 PF+ turbines. These emission estimates are based on one startup/shutdown event in an hour for the combined cycle turbines. The Division will establish an hourly emission rate for CO emissions from the turbines during periods of startup/shutdown and will limit the combined number of hours of startup/shutdown for the combined cycle turbines to 1200 hours for EGU004 and EGU005.

6.1.3 VOC Emissions

6.1.3.1 Normal Operation

<u>Control Options</u>

Black Hills Power, Inc. identified the following applicable control technologies for reducing VOC emissions from the combined and simple cycle turbines at the CPGS:

Catalytic Oxidation
Catalytic Combustion (XONON)
Dry Low NO_x (DLN) burners
$SCONO_x$

Catalytic oxidation is a post combustion control technology that utilizes a catalyst to oxidize VOCs to CO_2 and water.

Catalytic combustion is a control technology that uses a catalyst inside the combustor where the air/fuel mixture passes through the catalyst as combustion occurs at lower temperatures compared to standard combustors.

DLN burners are incorporated into the design on the proposed turbines (LM6000 combustion turbines) at the CPGS and would represent good combustion practices.

$SCONO_x$ utilizes a single catalyst for the reduction of NO_x, CO, and VOCs and does not require a reagent such as ammonia. $SCONO_x$ combustion functions by oxidizing VOCs to CO_2 and water.

<u>Eliminate Technically Infeasible Options</u>

Catalytic combustion was eliminated from consideration as this technology is not commercially available for large turbines such as those proposed for the CPGS.

$SCONO_x$ technology was eliminated as being technically infeasible as this technology has not been applied and demonstrated on large-scale turbines such as those proposed for the CPGS.

Rank Remaining Technologies

The remaining VOC control technologies for the turbines in order of control effectiveness are an oxidation catalyst and DLN burners (good combustion practices).

Evaluate Remaining Technologies/Select BACT

Black Hills Power, Inc. proposed a VOC emission rate of 3 ppm at 15 percent (15%) O_2 (1-hour average based on stack testing) utilizing an oxidation catalyst for the combined turbines. The Division reviewed EPA's RBLC to compare previously permitted VOC emission rates for similar sources in other states against Black Hills Power, Incorporated's proposed VOC emission rate. The Division used process code 15.210 when searching the RBLC database. This code refers to combined cycle turbines greater than 25 megawatts utilizing natural gas.

Table 6-5: RBLC Sources Identified for VOC Emission Limits

CO Emission Rate (ppm_{vd} at 15% O_2)	Averaging Period	Unit	Permit Date	Company/Site	RBLC ID
Results Under Process Code 15.210 (Combined Cycle)					
2**	24-hr rolling average	210 MW	6/18/2015	Eagle Mountain Power – Eagle Mountain Steam Electric Station	TX-0751
4	3-hr average	1100 MW	4/1/2015	Colorado Bend II Power – Colorado Bend Energy Center	TX-0730
1	not specified	240 MW	12/19/2014	NRG Texas Power – S R Bertron Electric Generating Station	TX-0714
4	3-hr rolling	197 MW	12/1/2014	Victoria WLE – Victoria Power Station	TX-0710
2	not specified	2159 MMbtu/hr	11/21/14	Moundsville Power, LLC – Moundsville Combined Cycle Power Plant	WV-0025
4	1-hr	497 MW	11/20/2014	Southern Power Company – Trinidad Generating Facility	TX-0712

** Identified as "LAER" (Lowest Achievable Emission Rate) in the RBLC.

Based on the Division's review of the RBLC, a range of VOC emission rates have been determined to be representative of BACT by other permitting agencies. Given all of the above information, the Division has determined that a VOC emission rate of 3 ppm at 15% O_2 (1-hr average based on stack testing) is BACT for both the GE LM6000 PF and GE LM6000 PF+ turbines.

6.1.4.2 Startup/Shutdown

Black Hills Power, Inc. estimated that VOC emissions would be higher during periods of startup for both the combined cycle turbines as the oxidation catalyst would not be at the appropriate temperature for emission control. Black Hills Power, Inc. estimated that the VOC emission rate would be approximately 8.2 lb/hr for the GE LM6000 PF turbines, and 6.5 lb/hr for the GE LM6000 PF+ turbines. These emission estimates are based on one startup/shutdown event in an hour for the combined cycle turbines and two startup/shutdown events in an hour for the simple cycle turbines. The Division does not intend to establish limits during startup/shutdown periods as it is not possible to test for VOCs as these periods are not long enough in duration for valid reference method tests to be conducted.

6.1.4 PM/PM_{10}/$PM_{2.5}$ Emissions

Black Hills Power, Inc. identified good combustion practices, efficient particle filtration and clean fuels as control methodologies, which have been used for particulate matter control on combustion turbines. Black Hills Power, Inc. noted that no flue gas particulate control system have been required for natural gas fired turbines as evidenced by reviewing the RBLC. The Division reviewed the RBLC and noted that good combustion practices was deemed BACT for combined cycle combustion turbines. Black Hills Power, Inc. has proposed particulate emission rates of 4.0 lb/hr, based on good combustion practices, for the combined cycle turbines based on EPA Reference Methods 5 and 202. The Division will consider the proposed emission rates for total particulate matter utilizing good combustion practices as representing BACT for PM/PM_{10}/$PM_{2.5}$ for the combined cycle turbines.

6.1.5 SO_2 Emissions

Black Hills Power, Inc. identified that the proposed combined cycle turbines will utilize pipeline quality natural gas, which is inherently low in sulfur compounds. Additionally, Black Hills Power, Inc. has stated that no feasible add-on SO_2 control technologies have been used on combustion turbines utilizing pipeline quality natural gas as fuel. As part of this demonstration, Black Hills Power, Inc. provided query results of the EPA's RBLC database which indicates that pipeline quality natural gas has been determined to represent BACT in permitting actions conducted in other States. Therefore, the Division will consider the use of pipeline quality natural gas as being representative of BACT for SO_2 emissions from the combined cycle turbines at the CPGS.

6.1.6 Ammonia Emissions

Black Hills Power, Inc. proposed ammonia emissions of 5.7 lb/hr for the GE LM6000 PF turbine and 6.5 lb/hr for the GE LM6000 PF+ turbines, based on a maximum ammonia slip value of 10 ppm_{vd} at 15% O_2. After reviewing ammonia emissions for sources equipped with SCR in the State, the Division determined that the proposed emission rates represent BACT for ammonia emissions resulting from the installation and operation of SCR on the combined cycle turbines.

6.2 Auxiliary Boiler

6.2.1 NO_x Emissions

Control Options

Black Hills Power, Inc. identified the following applicable control technologies for reducing NO_x emissions from the proposed auxiliary boiler (EP14) at the CPGS:

- Good Combustion Practices
- Low NO_x burners (LNB)

• LNB with Flue Gas Recirculation (FGR)
• Selective Catalytic Reduction (SCR)
• Selective Non-catalytic Reduction (SNCR)
• Non-selective Catalytic Reduction (NSCR)

Good combustion practices (GCP) include proper burner design, optimizing the air and fuel flow rates, and proper maintenance practices to find the optimum combustion efficiency while minimizing NO_x emissions.

Low NO_x burners (LNB) limit NO_x formation by controlling the stoichiometric and temperature profiles of the combustion process in each burner zone.

Flue gas recirculation (FGR) reduces NO_x emissions by recirculating a portion of the flue gas into the main combustion chamber. This process reduces the peak flame temperature and lowers the percentage of oxygen in the combustion air/fuel gas mixture reducing thermal NO_x formation.

Selective Catalytic Reduction (SCR) is a post-combustion NO_x control technology that can be used on boilers. SCR reduces NO_x emissions by injecting ammonia into the exhaust gas stream upstream of a catalyst. The ammonia reacts with NO_x on the catalyst to form molecular nitrogen and water vapor. For the SCR system to operate properly, the exhaust gas must be within a temperature range of 450 to 850 °F.

Selective non-catalytic reduction (SNCR) reduces NO_x emissions by injection of ammonia or urea into the exhaust gas stream. SNCR is similar to SCR in that both systems use ammonia to react with nitrogen; however, SNCR operates at higher temperatures than SCR and does not use catalyst. The effective temperature range for SNCR is 1600 to 2200 °F.

Non-selective catalytic reduction (NSCR) utilizes a catalyst without injected reagents to reduce NO_x emissions in an exhaust gas stream. NSCR is only effective in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen. This control is typically utilized in automobile exhaust and stationary rich-burn internal combustion engines.

<u>Eliminate Technically Infeasible Options</u>

Selective non-catalytic reduction (SNCR) was eliminated from consideration as the exhaust temperature of the auxiliary boiler will be less than what is necessary for this control technology.

Non-selective catalytic reduction (NSCR) was eliminated from consideration as the oxygen concentration in the exhaust gases are outside the range necessary for this technology to work effectively.

<u>Rank Remaining Technologies</u>

The following NO_x control technologies are ranked according to the level of emission rates achievable (control effectiveness): (1) SCR, (2) LNB with FGR, and (3) Good Combustion Practices.

<u>Evaluate Remaining Technologies/Select BACT</u>

Black Hills Power, Inc. proposed the use of LNBs with FGR for BACT for the auxiliary boiler; therefore, further evaluation of SCR was warranted. Table 6-6 shows the cost effectiveness of SCR for NO_x control from the auxiliary boiler.

Table 6-6: Comparison of NO_x Control for the Auxiliary Boiler

Control	Base Case (LNB with FGR)	LNB with FGR and SCR	LNB with FGR and SCR
Control Level (lb/MMBtu)	0.0175	0.0058	0.0035
Capital Cost ($)	0	154,825	165,187
Total Annualized Cost ($)	0	82,890	86,704
Baseline Emission Rate (tpy)	1.9	1.9	1.9
Controlled Emission Rate (tpy)	1.9	0.6	0.4
Emission Reduction (tpy)	0	1.3	1.5
Cost Effectiveness ($/ton)	--	63,762	57,803
Incremental Cost ($)	--	82,890	3,814
Incremental Reduction (tpy)		1.3	0.2
Incremental Cost Effectiveness ($/ton)	--	63,762	19,070

The Division reviewed EPA's RBLC database to compare previously permitted NO_x emission rates for similar sources in other states against Black Hills Power, Incorporated's proposed NO_x emission rate. The Division used process code 13.310 when searching the RBLC database. These codes refer to commercial/industrial sized boilers/furnaces less than 100 MMBtu/hr in size utilizing natural gas. Table 6-7 shows permitted emission rates for the most recently permitted emission units identified in the RBLC.

Table 6-7: RBLC Sources Identified for NO_x Emission Limits

NO_x Emission Rate (lb/MMBtu)	Averaging Period	Unit	Permit Date	Company/Site	RBLC ID
Results Under Process Code 13.310					
0.010	3-hr average	73.3	6/18/2015	Eagle Mountain Power	TX-0751
0.045	3-hr average	60	5/21/15	Delaware Basin Midstream – Ramsey Gas Plant	TX-0755
0.1	3-hr average	3	2/2/2015	Indeck Wharton – Indeck Wharton Energy Center	TX-0694
7 ppm	3-hr average	50	1/6/2015	Agrium – Kenai Nitrogen Operations	AK-0083
0.036	3-hr rolling	80	12/19/2014	NRG Texas Power – SR Bertron Electric Generating Station	TX-0714
0.0175	3-hr average	25.06	7/16/2014	Black Hills Power – Cheyenne Prairie Generating Station	WY-0075

Based on the cost effectiveness and incremental cost, Black Hills Power, Inc. has proposed LNBs with FGR with a NO_x emission rate of 0.0175 lb/MMBtu for the auxiliary boiler. The Division considers the cost effectiveness and incremental costs of going beyond LNBs with FGR for NO_x control for the auxiliary boiler to be economically unreasonable, as represented in Table 6-6. Additionally, Black Hills Power, Incorporated's proposed NO_x emission rate (0.0175 lb/MMBtu) for the 24.68 MMBtu/hr auxiliary boiler is comparable to the NO_x emission rates identified in the RBLC. Given the size of auxiliary boiler as compared to those listed in the RBLC, the Division will consider the proposed NO_x emission rate of 0.0175 lb/MMBtu from the auxiliary boiler utilizing LNBs and FGR as being representative of BACT.

6.2.2 CO Emissions

Control Options

Black Hills Power, Inc. identified the following applicable control technologies for reducing CO emissions from the auxiliary boiler at the CPGS:

- Good Combustion Practices
- Catalytic Oxidation

Catalytic oxidation is a post combustion control technology that utilizes a catalyst to oxidize CO to CO_2.

Eliminate Technically Infeasible Options

Black Hills Power, Inc. did not eliminate any CO control option as being technically infeasible for the auxiliary boiler.

Rank Remaining Technologies

The remaining CO control technologies for the auxiliary boiler in order of control effectiveness are an oxidation catalyst and good combustion practices.

Evaluate Remaining Technologies/Select BACT

Black Hills Power, Inc. proposed good combustion practices for BACT for the auxiliary boiler; therefore, further evaluation of the use of an oxidation catalyst was warranted. Table 6-8 shows the cost effectiveness of utilizing an oxidation catalyst for CO control.

Table 6-8: Comparison of CO Control for the Auxiliary Boiler		
Control	Base Case (LNB with FGR and good combustion practices)	Oxidation Catalyst with LNB and FGR
Control Level (lb/MMBtu)	0.0375	0.0074
Capital Cost ($)	0	57,750
Total Annualized Cost ($)	0	53,595
Baseline Emission Rate (tpy)	4.1	4.1
Controlled Emission Rate (tpy)	4.1	0.8
Emission Reduction (tpy)	0	3.3
Cost Effectiveness ($/ton)	--	16,241

The Division reviewed EPA's RBLC database to compare previously permitted CO emission rates for similar sources in other states against Black Hills Power, Incorporated's proposed CO emission rate. The Division used process code 13.310 when searching the RBLC database. These codes refer to commercial/industrial sized boilers/furnaces less than 100 MMBtu/hr in size utilizing natural gas. Table 6-9 shows permitted emission rates for the most recently permitted emission units identified in the RBLC.

Table 6-9: RBLC Sources Identified for CO Emission Limits					
CO Emission Rate (lb/MMBtu)	Averaging Period	Unit	Permit Date	Company/Site	RBLC ID
Results Under Process Code 13.310					
50 ppm	3-hr average	73.3	6/18/2015	Eagle Mountain Power	TX-0751
50 ppm	3-hr average	60	5/21/2015	Delaware Basin Midstream – Ramsey Gas Plant	TX-0755
0.04	3-hr average	3	2/2/2015	Indeck Wharton – Indeck Wharton Energy Center	TX-0694
50 ppm	3-hr average	50	1/6/2015	Agrium – Kenai Nitrogen Operations	AK-0083
0.037	3-hr rolling	80	12/19/2014	NRG Texas Power – SR Bertron Electric Generating Station	TX-0714
0.0175	3-hr average	25.06	7/16/2014	Black Hills Power – Cheyenne Prairie Generating Station	WY-0075

Based on the cost effectiveness and incremental cost, Black Hills Power, Inc. has proposed good combustion practices with LNBs and FGR with a CO emission rate of 0.0375 lb/MMBtu for the auxiliary boiler. The Division considers the cost effectiveness and incremental costs of going beyond good combustion practices for CO control for the auxiliary boiler to be economically unreasonable, as represented in Table 6-8. In addition, Black Hills Power, Incorporated's proposed CO emission rate (0.0375 lb/MMBtu) for the 24.68 MMBtu/hr auxiliary boiler is comparable to the CO emission rates identified in the RBLC. Given the size of auxiliary boiler as compared to those listed in the RBLC, the Division will consider the proposed CO emission rate of 0.0375 lb/MMBtu from the auxiliary boiler good combustion practices utilizing LNBs and FGR as being representative of BACT.

6.2.3 PM/PM_{10}/$PM_{2.5}$ Emissions

Identify Control Technologies

Black Hills Power, Inc. identified good combustion practices and clean fuels (natural gas) as potential control options for particulate matter from the auxiliary boiler. The Division also considers post-combustion control of particulate (i.e., baghouse) to be an effective means of reducing particulate emissions.

Eliminate Technically Infeasible Options

Black Hills Power, Inc. did not eliminate any identified PM/PM_{10}/$PM_{2.5}$ control option as being technically infeasible for the auxiliary boiler. Based on the relatively small amount of particulate emissions estimated for the auxiliary boiler, the Division considers post-combustion controls to be unreasonable.

Rank Remaining Technologies

The only remaining technology is the use of good combustion practices and clean fuels for the auxiliary boiler.

Evaluate Remaining Technologies/Select BACT

Black Hills Power, Inc. has proposed the use of good combustion practices along with clean fuels (natural gas) as being representative of BACT for the auxiliary boiler with a PM/PM_{10}/$PM_{2.5}$ emission rate of 0.0175 lb/MMBtu. The Division reviewed EPA's RBLC to compare previously permitted PM/PM_{10}/$PM_{2.5}$ emission rates for similar sources in other states against Black Hills Power, Incorporated's proposed PM/PM_{10}/$PM_{2.5}$ emission rate. The Division used process code 13.310 when searching the RBLC database. These codes refer to commercial/industrial sized boilers/furnaces less than 100 MMBtu/hr in size utilizing natural gas. Table 6-10 shows permitted emission rates for the most recently permitted emission units identified in the RBLC.

Table 6-10: RBLC Sources Identified for $PM/PM_{10}/PM_{2.5}$ Emission Limits					
$PM/PM_{10}/PM_{2.5}$ Emission Rate (lb/MMBtu)	Averaging Period	Unit	Permit Date	Company/Site	RBLC ID
Results Under Process Code 13.310					
0.0074	3-hr average	50	1/6/2015	Agrium – Kenai Nitrogen Operations	AK-0083
0.0175	3-hr average	25.06	7/16/2014	Black Hills Power – Cheyenne Prairie Generating Station	WY-0075
0.0075	3-hr average	45	6/9/2014	Old Dominion Electric – Wildcat Point Generation	MD-0042
0.005	3-hr average	93	5/8/2014	CPV Maryland, LLC – CPV St. Charles	MD-0041
0.008	3-hr average	60.1	4/14/2014	Interstate Power and Light – Marshalltown Generating Station	IA-0107

Based on a review of the RBLC, Black Hills Power, Incorporated's proposed $PM/PM_{10}/PM_{2.5}$ limit is higher than determinations made in other areas, but it also includes the condensable fraction. Given the size of the units listed in the RBLC and their respective emission limits and averaging periods as compared to the auxiliary boiler, the Division will consider a $PM/PM_{10}/PM_{2.5}$ emission rate 0.0175 lb/MMBtu (filterable + condensable) as being representative of BACT for the natural gas package boiler.

6.2.4 VOC Emissions

Control Options

Black Hills Power, Inc. identified the following applicable control technologies for reducing VOC emissions from the auxiliary boiler at the CPGS:

- Good Combustion Practices
- Catalytic Oxidation

Catalytic oxidation is a post combustion control technology that utilizes a catalyst to oxidize VOCs to CO_2.

Eliminate Technically Infeasible Options

Black Hills Power, Inc. did not eliminate any VOC control option as being technically infeasible for the auxiliary boiler.

Rank Remaining Technologies

The remaining VOC control technologies for the turbines in order of control effectiveness are an oxidation catalyst and good combustion practices.

<u>Evaluate Remaining Technologies/Select BACT</u>

Black Hills Power, Inc. has proposed the use of good combustion practices along with clean fuels (natural gas) as being representative of BACT for the auxiliary boiler with a VOC emission rate of 0.0017 lb/MMBtu. The Division reviewed EPA's RBLC to compare previously permitted VOC emission rates for similar sources in other states against Black Hills Power, Incorporated's proposed VOC emission rate. The Division used process code 13.310 when searching the RBLC database. These codes refer to commercial/industrial sized boilers/furnaces less than 100 MMBtu/hr in size utilizing natural gas. Table 6-11 shows permitted emission rates for the most recently permitted emission units identified in the RBLC.

Table 6-11: RBLC Sources Identified for VOC Emission Limits					
VOC Emission Rate (lb/MMBtu)	Averaging Period	Unit	Permit Date	Company/Site	RBLC ID
Results Under Process Code 13.310					
4 ppm	3-hr average	73.3	6/18/2015	Eagle Mountain Power	TX-0751
0.0054	3-hr average	50	1/6/2015	Agrium – Kenai Nitrogen Operations	AK-0083
0.0017	3-hr average	25.06	7/16/2014	Black Hills Power – Cheyenne Prairie Generating Station	WY-0075
0.0033	3-hr average	45	6/9/2014	Old Dominion Electric – Wildcat Point Generation	MD-0042
0.0020	3-hr average	93	5/8/2014	CPV Maryland, LLC – CPV St. Charles	MD-0041
0.005	3-hr average	60.1	4/14/2014	Interstate Power and Light – Marshalltown Generating Station	IA-0107

[1] Value back calculated based on an emission rate of 0.14 tons per year in the RBLC.

Based on a review of the RBLC, Black Hills Power, Incorporated's proposed VOC emission limit (0.0017 lb/MMBtu) appears to be in line or lower than determinations made in other areas. In addition, Black Hills Power, Inc. provided a BACT analysis for controlling CO emissions (see Table 6-8), which the Division deemed to be economically unreasonable. Based on the CO cost analysis, the Division considers the cost to control VOC emissions to also be economically unreasonable as VOC emissions are a fraction (0.2 tpy) of the CO emissions (4.1 tpy) estimated from the auxiliary boiler. Therefore, the Division will consider the proposed VOC emission rate 0.0017 lb/MMBtu as being representative of BACT for the natural gas package boiler.

6.3 Cooling Tower

Black Hills Power, Inc. identified potential control technologies for $PM/PM_{10}/PM_{2.5}$ from cooling towers as the use of drift eliminators, and limiting dissolved solids in cooling tower water. A drift eliminator is a device that is installed within a cooling tower chimney, and consists of a series of wood slats or plastic packing that mechanically captures and coalesces the water droplets, preventing their release to the atmosphere.

Black Hills Power, Inc. removed limiting dissolved solids in the cooling tower water from further consideration as limiting dissolved solids would increase the water consumption of the CPGS, and would require doubling the design flow rate of the zero discharge wastewater treatment system, doubling the size of the evaporation ponds or wastewater discharge to the municipal sewer. As a result, Black Hills Power, Inc. has proposed the use of drift eliminators with a design drift rate of 0.0005 percent of circulating water flow rate. The Division considers the use of drift eliminators with a 0.0005% drift rate as being representative of BACT for particulate emissions from the cooling towers.

7.0 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The proposed combustion turbines at the CPGS will be subject to the requirements of 40 CFR part 60, subpart KKKK – *Standards of Performance for Stationary Combustion Turbines*. This subpart applies to a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. This subpart limits NO_x emissions from combined cycle combustion turbines to 25 ppm at 15 percent oxygen (O_2) or 1.2 pounds (lbs) per megawatt-hour (MWh) on a 30-unit operating day rolling average. The proposed BACT limit of 3 ppm_{vd} for the combined cycle turbines are lower than the NSPS limits.

In addition to the NO_x limits, subpart KKKK also specifies a SO_2 emission limit for new turbines that are located in continental areas of 0.9 lb/MW-hr gross energy output. In accordance with subpart KKKK, Black Hills Power, Inc. may comply with the standard directly, or accept a limit of 0.060 lb SO_2/MMBtu on the sulfur content of the fuel.

The proposed auxiliary boiler will be subject to 40 CFR part 60, subpart Dc – *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*. This subpart applies to each steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). There are no emission requirements for natural gas fired units under the subpart.

8.0 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPs)

The proposed combustion turbines are not subject to 40 CFR part 63, subpart YYYY – *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* as the CPGS is not a major source of HAPs as defined in Chapter 6, Section 3 of the WAQSR.

The proposed cooling tower is not subject to 40 CFR part 63, subpart Q – *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers*. This subpart applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources.

The auxiliary boiler is not subject to 40 CFR part 63, subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*. This is due to the fact that the CPGS is not a major source of hazardous air pollutants (see Table 3-2).

The auxiliary boiler is not subject to 40 CFR part 63, subpart JJJJJJ – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources*. This is due to the fact that the auxiliary boiler meets the definition of a gas-fired boiler under the subpart, and gas-fired boilers are specifically listed as not being subject to the subpart or any of its requirements. A gas-fired boiler is defined in the subpart to include any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuels only during periods of natural gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuels.

The CPGS is not subject to 40 CFR part 63, subpar UUUUU – *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units* as the stationary combustion turbines would be covered by 40 CFR part 63, subpart YYYY.

9.0 PROJECTED IMPACT ON CLASS II AREA AIR QUALITY

9.1 DISPERSION MODEL SELECTION AND INPUT DATA

Air quality impacts in the Class II areas surrounding the proposed project were predicted using AERMOD, which is the EPA-preferred dispersion model for transport distances up to fifty kilometers (km) as described in the EPA's *Guideline on Air Quality Models* (Appendix W of 40 CFR Part 51). Version 14153 of AERMOD was used to predict ambient concentrations of air pollutants in Class II areas for comparison to Wyoming Ambient Air Quality Standards (WAAQS), National Ambient Air Quality Standards (NAAQS), and Prevention of Significant Deterioration (PSD) increments. The applicant modeled impacts from the following pollutants:

- Nitrogen Dioxide (NO_2)
- Sulfur Dioxide (SO_2)
- Carbon Monoxide (CO)
- Particulate matter less than 10 microns in diameter (PM_{10})
- Particulate matter less than 2.5 microns in diameter ($PM_{2.5}$)

The ambient air impact analysis was conducted by the applicant in accordance with the modeling protocol that was approved by the Division titled *Proposed Protocol for an Air Quality Modeling Analysis of the CPGS* (CH2M Hill, January 2015). The Division reviewed the applicant's model runs to verify proper model setup, and modeling results reported here were obtained from the Division's verification model runs. All model runs used the EPA-recommended regulatory default options for AERMOD:

- No exponential decay
- Elevated terrain effects
- Stack-tip downwash
- Calms processing
- Missing meteorological data processing

The AERMOD modeling system includes two regulatory preprocessors: 1) the AERMET meteorological preprocessor, and 2) the AERMAP terrain and receptor grid preprocessor. Data prepared for AERMOD input from these two preprocessors as well as input data prepared for building downwash effects, emissions, and source release parameters are described in the following sections.

9.1.1 Meteorological Data

The applicant used a meteorological dataset to drive the AERMOD model that was supplied by the Division and included five years of surface data collected from January 1, 2008 through December 31, 2012 at the Automated Surface Observing System (ASOS) meteorological tower at the Municipal Airport in Cheyenne, Wyoming. The AERMET processing included the use of 1-minute ASOS wind data in TD-6405 format. These 1-minute files were used to reduce the number of calm/missing hours that result from the use of the standard surface files that utilize a single observation to represent a given hour. AERMET version 14134, which is capable of averaging the 1-minute ASOS data for each hour, was used to produce the dataset. Upper-air data consisting of twice-daily soundings from the nearest upper-air monitoring station (Denver, Colorado) were merged with the surface meteorological data.

Stage 3 of AERMET processing (also called the METPREP stage) requires the input of surface characteristics of the area from which the surface meteorological data were collected. These surface characteristics, which are used by AERMET to determine heat fluxes and atmospheric stability, include:

- midday albedo – fraction of solar radiation reflected at the surface
- daytime Bowen ratio – indicator of surface moisture
- surface roughness length – height of obstacles to the wind flow

Surface characteristics for this dataset were entered for twelve sectors on a seasonal basis, and were determined using the EPA AERSURFACE program (08009). This program makes use of electronic land cover data from the U.S. Geological Survey to calculate surface characteristics for a given monitoring station. The seasonal classifications for the year followed the standard AERMET/AERSURFACE breakdown (e.g. summer = June, July, and August).

An AERSURFACE user has the option of choosing Bowen ratios that are tailored for dry, average, or wet conditions. The Division compiled annual precipitation totals for 2008-2012 for the Cheyenne area and compared them to long-term records. Any yearly total in the upper 30th-percentile of the 30-year record could be classified as “wet”. Similarly, any yearly total in the lower 30th-percentile could be classified as “dry”, and any yearly total in the middle 40th-percentile could be classified as “average”. In this case, 2006 was classified as “dry”, 2009 was classified as “wet”, and the three remaining years fell into the “average” category.

A wind rose for the 2010 data is presented in Figure 9-1.

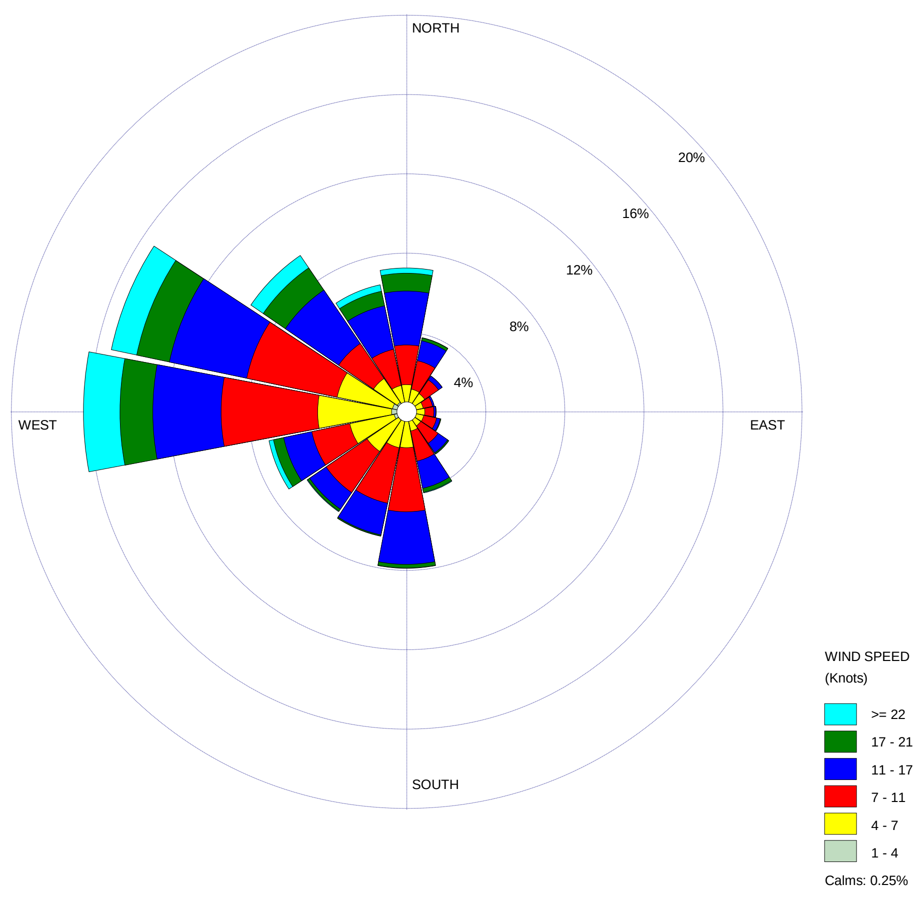
Figure 9-1: Wind Rose for Cheyenne, Wyoming

WIND ROSE PLOT:

Cheyenne 08-12 Wind Rose

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **Start Date: 1/1/2008 - 00:00** **End Date: 12/31/2012 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **0.25%**	TOTAL COUNT: **43782 hrs.**	
	AVG. WIND SPEED: **10.60 Knots**	DATE: **11/6/2013**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

9.1.2 Receptor Grid

The base receptor grid for the dispersion modeling analysis was a discrete Cartesian grid with an origin at the approximate center of the proposed station and a total of 4,652 receptors distributed as follows:

- 50-meter (m) spacing along the ambient air boundary of the facility
- 100-m spacing to a distance of one kilometer (km) from the grid origin
- 250-m spacing to a distance of 3 km from the grid origin
- 500-m spacing to a distance of 10 km from the grid origin
- 1000-m spacing to a distance of 25 km from the grid origin

Receptor elevations and hill heights were determined from electronic data contained in National Elevation Dataset (NED) files at 1/3 arc second (10-m) resolution. The base elevations of all structures and stacks for the CPGS were obtained from engineering site plans. The base receptor grid configuration is shown in Figure 9-2. All UTM coordinates used in the modeling were based on the NAD 83 datum (UTM Zone 13).

9.1.3 Building Profile Input Program (BPIP)

Building downwash was considered in the modeling analysis by entering building corners and building heights into the EPA's Building Profile Input Program (BPIP-PRIME). Chapter 6, Section 2(d) of the WAQSR dictates that the modeling of a point source to demonstrate compliance with an ambient air quality standard cannot account for any amount of the stack height that exceeds Good Engineering Practice (GEP) stack height. In this case, point sources for the CPGS were all modeled with stack heights that were below GEP stack height. Figure 9-3 shows the location of plant structures relative to the ambient air boundary. Table 9-1 lists the structures shown in Figure 9-3 and the heights of each structure.

9.1.4 Emissions and Source Release Parameters

Figure 9-4 shows the relative locations of the air emission sources at the CPGS. Modeled emissions and stack parameters for those sources are presented in Tables 9-2 through 9-5. Table 9-2 lists model input parameters for the point sources; including UTM coordinates, base elevations, stack heights, and stack diameters. Exit velocities and exit temperatures for all of the point sources, with the exception of the combustion turbines, are also listed in Table 9-2. The exit velocities and exit temperatures for the turbines, which vary according to load and ambient temperature, are shown in Table 9-3. A full range of load conditions, including 100%, 75%, and 50% loads with ambient temperatures of 0º F, 60º F, and 108º F were modeled for the turbines to ensure that worst case conditions were captured. Emission rates for all of the modeled load scenarios for the turbines are listed in Table 9-4. Emissions for other ancillary sources such as the inlet air heaters and chillers, fuel gas heaters, a cooling tower, and a diesel generator and fire pump, are shown in Table 9-5.

Figure 9-2: Receptor Grid Configuration

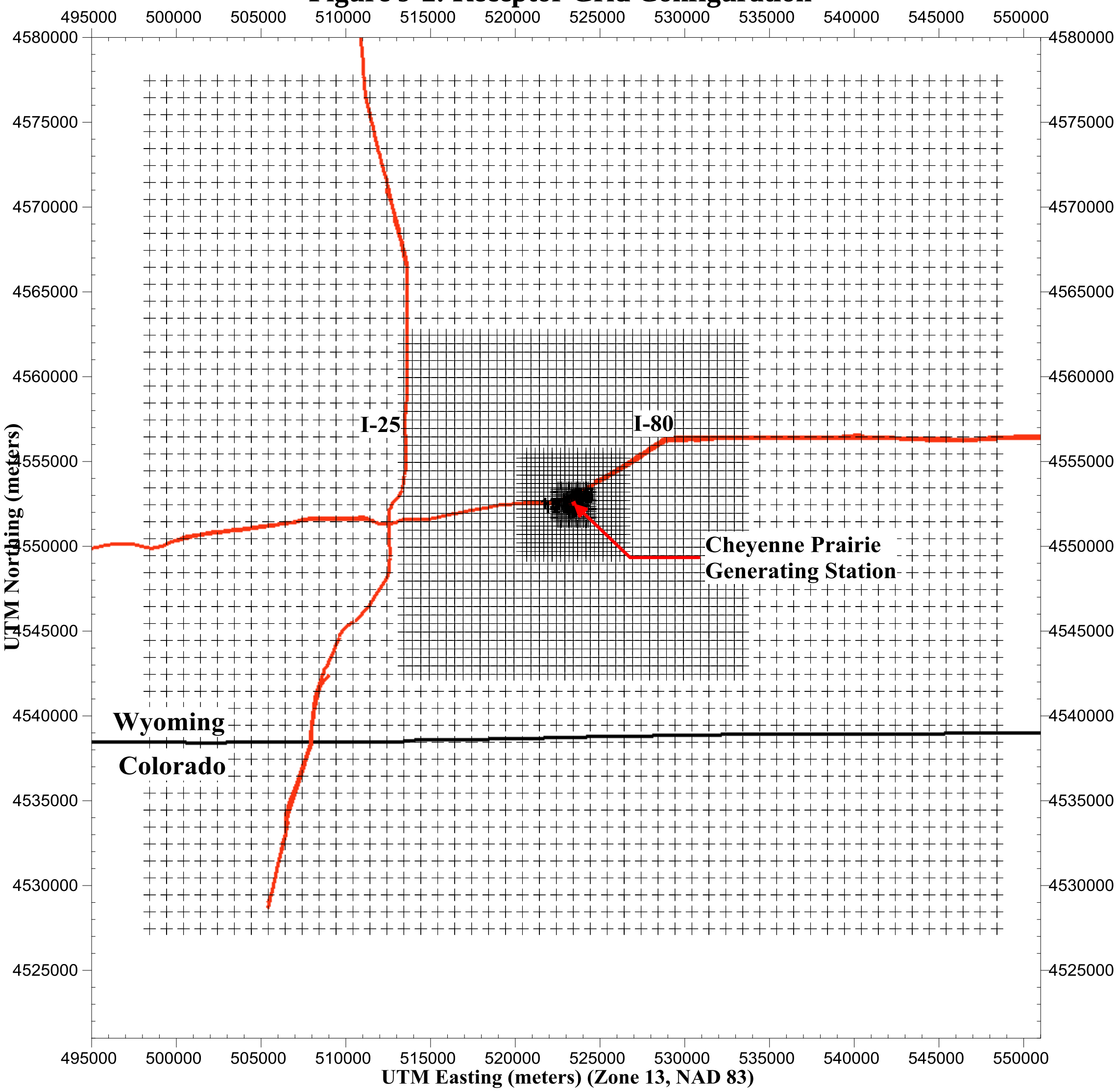


Figure 9-3: CPGS Buildings

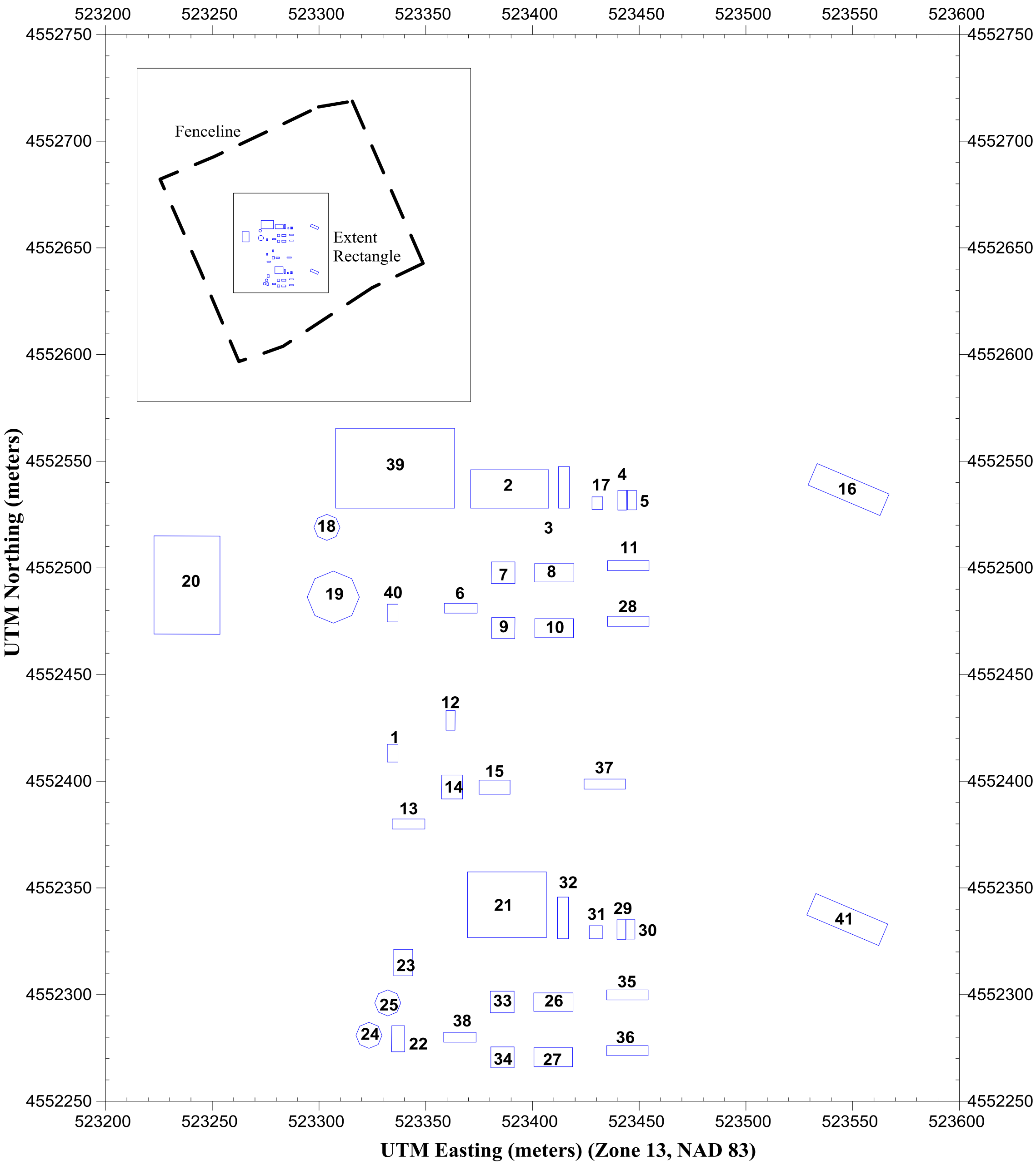


Table 9-1: Building Index and Heights

Figure ID	Description	Height (m)
1	Generator Step Up Transformer 2	7.55
2	Steam Turbine & Auxiliaries a	15.24
3	STG Auxiliary Power Enclosure	5.57
4	Inlet Air Heater 1	4.57
5	Inlet Air Heater 4	4.57
6	CTG Power Control Module 1	5.57
7	Gas Turbine Generator & Auxiliaries 1A	11.37
8	Boiler Feed Pump Enclosure 1A	16.46
9	Gas Turbine Generator & Auxiliaries 1B	11.37
10	Boiler Feed Pump Enclosure 1B	16.46
11	CTG Auxiliary Power Enclosure 1a	5.57
12	Inlet Air Heater 5	4.57
13	CTG Power Control Module 2	5.57
14	Gas Turbine Generator & Auxiliaries 2	11.37
15	Selective Catalyst Reduction 2	9.87
16	CTW Cooling Tower 1	12.8
17	Auxiliary Boiler	4.57
18	Demineralized Water Tank	12.19
19	Fire/Service Water Tank	12.19
20	New Warehouse	4.88
21	Steam Turbine & Auxiliaries 3	6.1
22	Fire Water Pump House	4.27
23	Generator Step Up Transformer 3	7.55
24	Fire/Service Water Tank	12.19
25	Demineralized Water Tank	12.19
26	Boiler Feed Pump Enclosure 3A	16.46
27	Boiler Feed Pump Enclosure 3B	16.46
28	CTG Auxiliary Power Enclosure 1B	5.57
29	Inlet Air Heater 6	4.57
30	Inlet Air Heater 7	4.57
31	Auxiliary Boiler	4.57
32	STG Auxiliary Power Enclosure	5.57
33	Gas Turbine Generator & Auxiliaries 3A	11.37
34	Gas Turbine Generator & Auxiliaries 3B	11.37
35	CTG Auxiliary Power Enclosure 3A	5.57
36	CTG Auxiliary Power Enclosure 3B	5.57
37	CTG Auxiliary Power Enclosure 2	5.57
38	CTG Power Control Module 3	5.57
39	Administration Building	6.1
40	Generator Step Up Transformer 1	7.55
41	CTW Cooling Tower 2	12.8

Figure 9-4: CPGS Point Source Locations

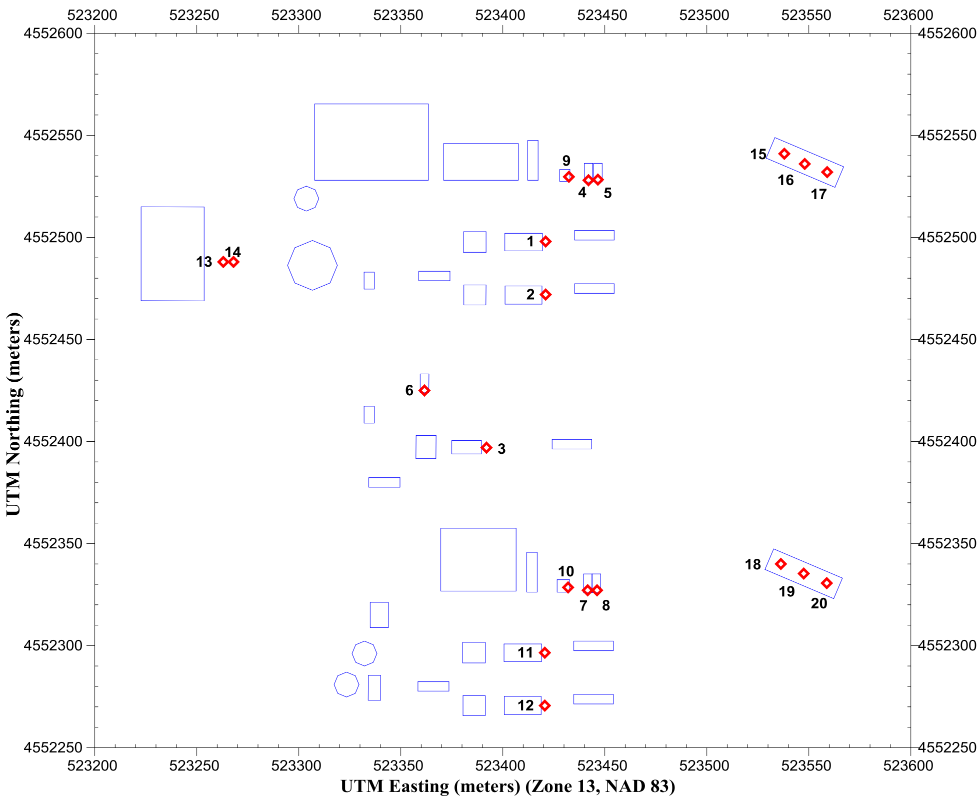


Table 9-2: CPGS – Point Source Stack Parameters

Map ID	Source ID	Description	UTM East (m)	UTM North (m)	Base Elev. (m)	Stack Height (m)	Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)
1	CTG1A	Combined Cycle Combustion PF Turbine 1A	523421	4552498	1809.6	24.38	*	*	2.44
2	CTG1B	Combined Cycle Combustion PF Turbine 1B	523421	4552472	1809.6	24.38	*	*	2.44
3	CTG2A	Simple Cycle Combustion Turbine 2A	523392	4552397	1809.6	24.38	*	*	2.82
4	INHTR001	Inlet Air Heater 1	523442	4552528	1809.6	6.10	344.3	0.013	0.76
5	INHTR002	Inlet Air Heater 2	523447	4552528	1809.6	6.10	344.3	0.013	0.76
6	INHTR003	Inlet Air Heater 3	523362	4552425	1809.6	6.10	344.3	0.013	0.76
7	INHTR004	Inlet Air Heater 4	523442	4552327	1809.6	6.10	344.3	0.013	0.76
8	INHTR005	Inlet Air Heater 5	523446	4552327	1809.6	6.10	344.3	0.013	0.76
9	AUXB1100	Auxiliary Boiler 1	523432	4552530	1809.6	14.48	497.0	13.647	0.71
10	AUXB2100	Auxiliary Boiler 2	523432	4552329	1809.6	14.48	492.0	12.652	0.71
11	CTG3A	Combined Cycle Combustion Turbine 3A (PF)	523421	4552297	1809.6	24.38	*	*	2.44
12	CTG3B	Combined Cycle Combustion Turbine 3B (PF)	523421	4552271	1809.6	24.38	*	*	2.44
11	CTG3A	Combined Cycle Combustion Turbine 3A (PF+)	523421	4552297	1809.6	24.38	*	*	2.74
12	CTG3B	Combined Cycle Combustion Turbine 3B (PF+)	523421	4552271	1809.6	24.38	*	*	2.74
13	GENER001	Diesel Generator	523263	4552488	1809.6	6.10	807.6	69.636	0.20
14	FIREP001	Diesel Fire Pump	523268	4552488	1809.6	6.10	723.2	48.303	0.15
15	CT1A	Cooling Tower 1 Cell A	523538	4552541	1809.6	7.93	305.4	5.390	9.14
16	CT1B	Cooling Tower 1 Cell B	523548	4552536	1809.6	7.92	305.4	5.390	9.14
17	CT1C	Cooling Tower 1 Cell C	523559	4552532	1809.6	7.92	305.4	5.390	9.14
18	CT2A	Cooling Tower 2 Cell A	523536	4552340	1809.6	7.92	305.4	5.390	9.14
19	CT2B	Cooling Tower 2 Cell B	523548	4552335	1809.6	7.92	305.4	5.390	9.14
20	CT2C	Cooling Tower 2 Cell C	523559	4552331	1809.6	7.92	305.4	5.390	9.14

Note: UTM coordinates = NAD 83, Zone 13.
*Temperature and exit velocity for turbines vary with operating scenario.

Table 9-3: Stack Parameters for Combined Cycle Combustion Turbine (various loads)

Operating Scenario	Turbine Load (%)	Ambient Temperature (ºF)	Combined Cycle Turbines - PF		Combined Cycle Turbines – PF+		Simple Cycle Turbines	
			Exit Temperature (K)	Exit Velocity (m/s)	Exit Temperature (K)	Exit Velocity (m/s)	Exit Temperature (K)	Exit Velocity (m/s)
Case 1	100	0	374.3	31.2	370.0	27.0	723.2	44.1
Case 2	100	60	376.5	29.5	372.0	25.7	735.4	42.5
Case 3	100	108	368.7	23.1	372.0	22.2	762.0	35.2
Case 4	75	0	368.2	25.3	381.0	22.9	729.8	36.7
Case 5	75	60	372.6	25.5	373.0	21.6	733.2	36.9
Case 6	75	108	363.7	19.3	373.0	19.3	776.5	30.4
Case 7	50	0	363.7	21.1	366.0	18.9	745.4	31.7
Case 8	50	60	362.6	18.6	364.0	16.6	781.5	29.4
Case 9	50	108	358.7	16.3	368.0	15.8	809.3	26.9

Table 9-4: Combustion Turbine Emission Rates (lb/hr)

Operating Scenario	NO_x (1-hr)	NO_x (Ann)	CO (1-hr& 8-hr)	$PM_{10/2.5}$ (24-hr and Ann)	SO_2 (All Avg Periods)
Combined Cycle Turbines - PF					
Case 1	4.60	5.83	3.74	4.0	0.48
Case 2	4.47	5.68	3.62	4.0	0.45
Case 3	3.41	4.53	2.77	4.0	0.34
Case 4	3.73	4.88	3.03	4.0	0.38
Case 5	3.59	4.72	2.91	4.0	0.36
Case 6	2.90	3.97	2.36	4.0	0.29
Case 7	3.25	4.36	2.64	4.0	0.30
Case 8	2.79	3.85	2.27	4.0	0.28
Case 9	2.42	3.44	1.96	4.0	0.23
Combined Cycle Turbines - PF+					
Case 1	5.26	6.30	4.27	4.0	0.58
Case 2	5.25	6.29	4.26	4.0	0.55
Case 3	4.48	5.57	3.64	4.0	0.47
Case 4	4.34	5.44	6.53	4.0	0.46
Case 5	4.45	5.55	3.62	4.0	0.45
Case 6	3.88	5.02	3.15	4.0	0.39
Case 7	3.75	4.89	3.05	4.0	0.38
Case 8	3.33	4.50	2.71	4.0	0.34
Case 9	3.03	5.22	2.46	4.0	0.32
Simple Cycle Turbines					
Case 1	7.67	8.19	5.60	4.0	0.48
Case 2	7.44	7.96	5.44	4.0	0.45
Case 3	5.68	6.20	4.15	4.0	0.34
Case 4	6.22	6.74	4.54	4.0	0.38
Case 5	5.98	6.50	4.37	4.0	0.36
Case 6	4.84	5.36	3.54	4.0	0.29
Case 7	5.42	5.95	3.96	4.0	0.30
Case 8	4.65	5.17	3.40	4.0	0.28
Case 9	4.03	4.55	2.94	4.0	0.23

Note: NO_x emission rates for combined cycle turbines based on Black Hills Corporations proposed BACT level of 3 ppmvd @15% O_2. NO_x emission rates for simple cycle turbines based on 5 ppmvd @15% O_2.

Table 9-5: Ancillary Source Emission Rates (lb/hr)

Source	NO_x (1-hr)	NO_x (Ann)*	CO (1-hr and 8-hr)	$PM_{10/2.5}$ (24-hr)	$PM_{10/2.5}$ (Ann)*	SO_2 (All Averaging Periods)
Inlet Air Heater 1	0.19	0.10	1.25	0.12	0.06	0.01
Inlet Air Heater 2	0.19	0.10	1.25	0.12	0.06	0.01
Inlet Air Heater 3	0.19	0.10	1.25	0.12	0.06	0.01
Inlet Air Heater 4	0.19	0.10	1.25	0.12	0.06	0.01
Inlet Air Heater 5	0.19	0.10	1.25	0.12	0.06	0.01
Auxiliary Boiler 1	0.44	0.44	0.94	0.44	0.44	0.01
Auxiliary Boiler 2	0.43	0.43	0.51	0.20	0.20	0.02
Diesel Generator	--	0.62	0.05	0.06	0.004	0.01
Diesel Fire Pump	--	0.05	0.02	0.08	0.002	0.00
Cooling Tower 1 Cell A	--	0.00	0.00	0.01	0.007	0.00
Cooling Tower 1 Cell B	--	0.00	0.00	0.01	0.007	0.00
Cooling Tower 1 Cell C	--	0.00	0.00	0.01	0.007	0.00
Cooling Tower 2 Cell A	--	0.00	0.00	0.01	0.007	0.00
Cooling Tower 2 Cell B	--	0.00	0.00	0.01	0.007	0.00
Cooling Tower 2 Cell C	--	0.00	0.00	0.01	0.007	0.00

*Notes:
1. The Inlet Air Heaters will operate during colder periods. The heaters were modeled at their short-term emission rates, assuming continuous operation, for the months of Nov-Apr only.
2. The Diesel Generator will operate a maximum of 500 hours per year, with no seasonal tendency. For long-term averaging periods, the generator was modeled with an average hourly rate (maximum hourly rate *500/8760).
3. The Diesel Fire Pump will operate a maximum of 250 hours per year, with no seasonal tendency. For long-term averaging periods, the generator was modeled with an average hourly rate (maximum hourly rate *250/8760).

9.2 WYOMING AMBIENT AIR QUALITY STANDARDS (WAAQS) ANALYSIS

9.2.1 Significant Impact Analysis

Initial significant impact modeling was conducted to determine if any pollutants ambient level exceeded the significant impact level (SIL) as determined by EPA. The results of the modeling is shown in Table 9-6. If these initial modeling results exceed the SIL a full-impact (cumulative) model run was conducted.

Table 9-6: Significant Impact Analysis Modeled Values				
Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m3)	Class II SIL (µg/m3)	Further Analysis Required
NO_2	1-Hour	39.0	7.5	Yes
	Annual	1.20	1.0	Yes
$PM_{2.5}$	24-Hour	11	1.2	Yes
	Annual	1.0	0.3	Yes
PM_{10}	24-Hour	11	5.0	Yes
	Annual	0.8	1.0	No
SO_2	1-Hour	6.3	7.8	No
	3-Hour	3.1	25.0	No
	24-Hour	0.84	5.0	No
	Annual	0.09	1.0	No
CO	1-Hour	827	2000	No
	8-Hour	292	500	No

9.2.2 Background Concentrations

Background concentrations were used to represent sources outside of the CPGS that were not explicitly input to full-impact (cumulative) model runs. The background concentrations used for the modeling are summarized in Table 9-7. Background NO_2, $PM_{2.5}$ and PM_{10} concentrations were taken from the Division's Cheyenne NCORE monitor. This monitor also captures the influence of mobile sources, including local auto/truck traffic, highways (I-25, I-80), and rail. Because of the high degree of uncertainty in emissions estimates and model representation for mobile sources, the mobile sources in the vicinity of the project were not explicitly modeled, but were conservatively accounted for with the background concentrations described above.

Table 9-7: Cheyenne Combustion Turbine Project Background Concentrations		
Pollutant	Averaging Period	Background Concentration (μg/m^3)
NO_2	1-Hour	67.7
	Annual	7.5
$PM_{2.5}$	24-Hour	12.0
	Annual	3.2
PM_{10}	24-Hour	46.3

Notes:
1) NO_2 background from 2012-2014 data from the AQD's Cheyenne NCORE site. 1-hour background: 3-year average of the 98th percentile of the daily maximums* (0.036 ppm); annual background: highest annual mean (0.004 ppm)
2) 24-Hour $PM_{2.5}$ background is the 3-year average of the 98th percentile of the 24-hour averages** from the AQD's Cheyenne NCORE site (2012-2014)
3) Annual $PM_{2.5}$ background is the 3-year average of the annual means** from the AQD's Cheyenne NCORE site (2012-2014)
4) 24-Hour PM_{10} background is the average of the overall highest 24-hour average from the AQD's Cheyenne NCORE site (2012-2014)
* per EPA memo *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (T. Fox, 1 Mar 11)
** per EPA memo *Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS* (S. Page, 23 Mar 10)

9.2.3 Nitrogen Dioxide (NO_2)

Sources of nitrogen oxide (NO_x) emissions from the CPGS were initially modeled to determine if the station would produce a significant modeled impact. Maximum modeled impacts were then compared to modeling significance levels to determine if full-impact (cumulative) modeling would be necessary.

Two sources at the CPGS, the diesel fire pump and the diesel emergency generator, were not included in the modeling for the 1-hour NO_2 standard. The diesel generator is used to provide emergency power for the station, and will normally operate for testing that is expected to occur once per week. Total annual operating hours for the generator is 500 or less. The diesel fire pump is used to provide fire protection water for the station, and is also expected to normally operate only during testing that will occur approximately once per week. Total annual operating hours for the fire pump is 250 or less. Because of the intermittent nature of the operation of these two sources and the probabilistic form of the 1-hour NO_2 NAAQS, the Division excluded them from the 1-hour NO_2 modeling, based on EPA modeling guidance as described in the EPA memo *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (Tyler Fox, EPA Air Quality Modeling Group Leader, hereafter referred to as the "3/1/2011 EPA memo"). Emissions from the diesel fire pump and the diesel emergency generator were included in the modeling for the annual NO_2 standard, in keeping with the 3/1/2011 EPA memo.

Each of the combined cycle combustion turbines are expected to be in startup/shutdown mode for approximately 600 hours per year. The simple cycle turbine is expected to be in startup/shutdown mode for approximately 300 hours per year. Given the intermittent nature of the startup/shutdown mode for the turbines, 1-hour NO_2 modeling of the turbines was performed with the short-term emission rates associated with normal operation only. This approach is in keeping with the discretion afforded reviewing authorities in the 3/1/2011 EPA memo regarding 1-hour NO_2 modeling. Startup-shutdown emissions were incorporated into the modeled long-term emission rates for the turbines for the annual NO_2 modeling.

The EPA's 3/1/2011 memo also outlines modeling procedures that can be used to estimate the conversion of NO_x emissions to NO_2. Specifically, the memo describes a three-tiered approach:

- Tier 1 = assume a 100% conversion of NO_x to NO_2
- Tier 2 = assume conversion of NO_x to NO_2 based on a default conversion ratio
- Tier 3 = detailed analysis on a case-by-case basis

Given that NO_x emissions from the modeled sources initially consist of mostly nitric oxide (NO), an assumption that 100% of all NO_x emissions immediately convert to NO_2 (Tier 1), or even an assumption that 75% or 80% of all NO_x emissions immediately convert to NO_2 (Tier 2), is too conservative. The Division conducted all modeling for NO_2 using a detailed (Tier 3) option within AERMOD.

9.2.3.1 Tier 3

Tier 3 allows for a detailed analysis of the estimated conversion to NO_2. Detailed methods available for use in AERMOD include the Ozone Limiting Method (OLM) and the Plume Volume Molar Ratio Method (PVMRM). The applicant chose to use the OLM option within AERMOD to estimate NO_2 impacts.

The OLM option requires the input of an in-stack NO_2/NO_x ratio for each point source, and for this analysis the applicant used a value of 0.5 for each source, as recommended in the 3/1/2011 EPA memo as a default value in the absence of source-specific data. An additional input requirement for OLM is the ambient equilibrium ratio for the conversion of NO_x to NO_2. For this analysis, the applicant used the value of 0.80 that is recommended in the 3/1/2011 memo as a default ambient ratio for the 1-hour NO_2 standard.

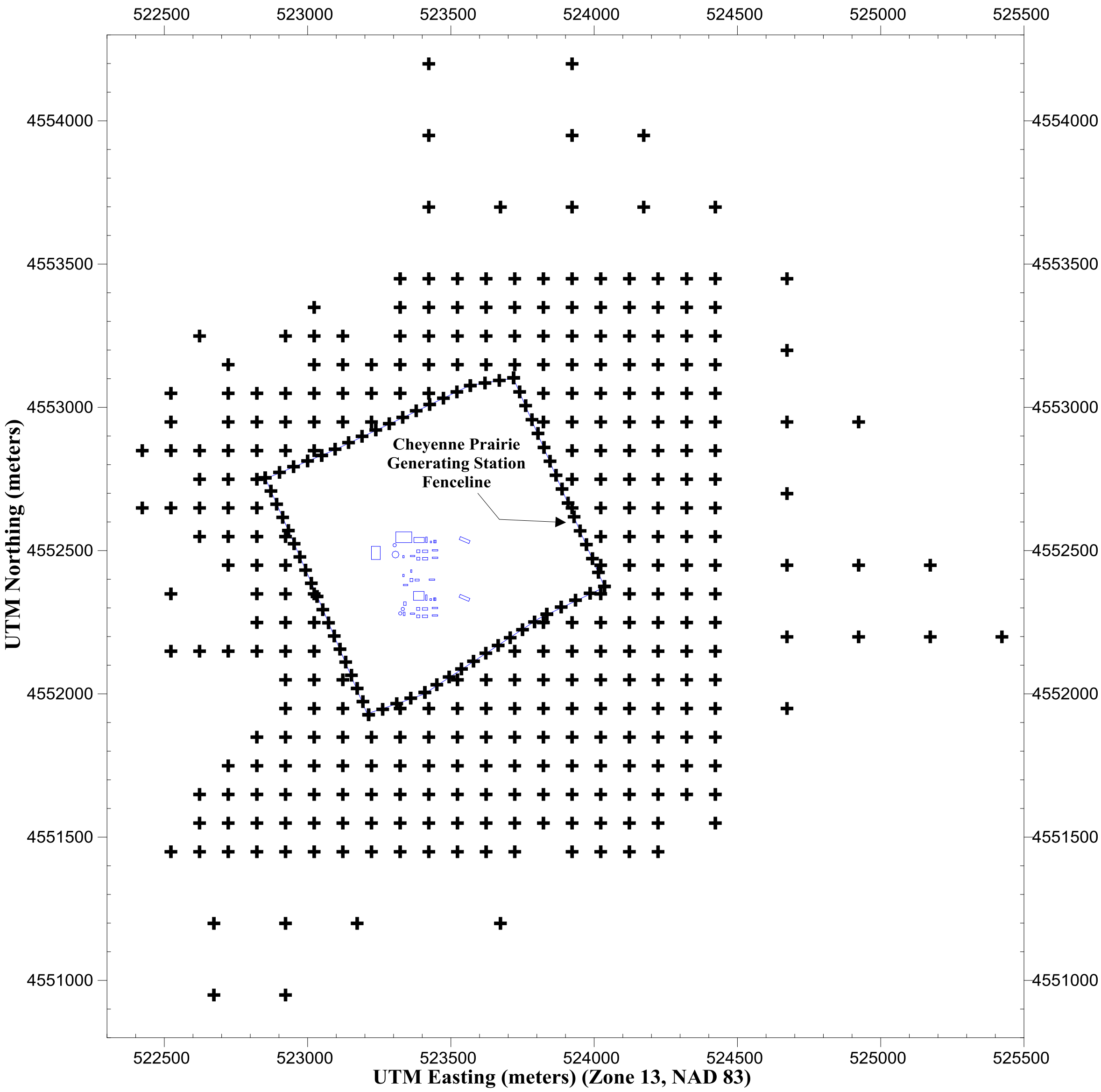
OLM also requires background ozone data in the form of hourly concentrations measured at a representative site. The Division collects hourly ozone data at the Cheyenne NCore monitoring site, but given that the National Core (NCore) site has only been operating since June of 2010, not enough data is available to couple with the Cheyenne meteorological data used in the modeling (spanning 2008 through 2012). The Division compared NCore ozone data to data available from other nearby sites, including Fort Collins, Colorado and Greeley, Colorado, and the data from the Fort Collins West site (site# 08-069-0011) was found to be most representative of Cheyenne.

Another consideration for the use of OLM is the OLMGROUP option, which allows sources whose plumes overlap to compete for the available background ozone rather than making all background ozone available to each individual source. This approach is recommended in recent EPA guidance memos for 1-hour NO_2 modeling (3/1/11, 6/28/10) to avoid overestimation of NO_2 concentrations that might result from allowing the full background ozone amount to be available for all sources. For the modeling described here, the OLMGROUP option was applied to each turbine source group (Cases 1 through 9) for the preliminary (project only) modeling that included various load options for the turbines and to all sources for the cumulative (NAAQS) model runs.

For the 1-hour model runs that were used to determine if a significant impact would be predicted for the proposed project, Case 1 for the five turbines (100% load, 0º F ambient temperature) yielded the highest overall impacts for each of the five years of meteorology that were used for the modeling. Using the Case 1 results, the highest modeled 1-hour impacts at each receptor were averaged over the five years of meteorological data, as recommended by the 3/1/2011 EPA memo. Those receptors for which this average exceeded the interim significant impact level of 7.5 $\mu g/m^3$ were used as the receptor grid for the cumulative impact model runs for the 1-hour averaging period. Figure 9-5 shows the receptors that yielded a significant impact. Based on the results of the significant impact modeling, the five turbines were input to the cumulative 1-hour model runs using the Case 1 configuration.

For the model runs used to determine significant impacts for the annual averaging period, Case 9 for the five turbines (50% load, 108º F ambient temperature) yielded the highest overall impacts for each of the five years of meteorology. Using the Case 9 results, the radius of significant impact was determined by identifying the most distant receptor (for each year) that yielded a predicted impact above the annual average significant impact level of 1.0 $\mu g/m^3$. The largest radius of impact was 0.5 km. The Division reduced the base receptor grid to those receptors that showed a significant impact to create the receptor grid for the full-impact analysis.

Figure 9-5: Significant Impact Receptors for 1-Hour NO_2



The maximum modeled 1-hour impact, based on the 98th percentile of the annual distribution of daily maximum concentrations at each receptor averaged across all years modeled, was 62.3 μg/m^3. With the addition of the 1-hour background concentration of 67.7 μg/m^3, the total predicted 1-hour impact is 130.0 μg/m^3, which is well below the 1-hour NAAQS for NO_2.

The highest predicted annual concentration was 3.0 μg/m^3. With the addition of the annual background level of 7.5 μg/m^3, the total predicted impact of 10.5 μg/m^3 is well below the annual NAAQS/WAAQS. The maximum modeled annual impact of 3.0 μg/m^3 is also below the annual PSD increment for NO_2 of 25 μg/m^3. Table 9-8 presents a summary of the NO_2 modeling results.

Table 9-8: Results of WAAQS/NAAQS Modeling for NO_2

Averaging Period	Maximum Modeled Impact (µg/m³)	Background Concentration (µg/m³)	Total Predicted Impact (µg/m³)	WAAQS/NAAQS (µg/m³)
1-Hour*	62.3	67.7	130.0	188
Annual	2.8	7.5	10.3	100
	2.6		10.1	
	2.7		10.2	
	2.7		10.2	
	3.0		10.5	

* 98^{th} percentile of the annual distribution of daily maximum 1-hour modeled concentrations averaged across the number of years modeled.

9.2.5 Particulate Matter ($PM_{2.5}$)

All sources of particulate matter at the CPGS were initially modeled for comparison to the modeling significance levels. As shown in Tables 9-4 and 9-5, the estimated emissions of PM_{10} were assumed to equal $PM_{2.5}$ for all sources at the CPGS. This allowed the Division to utilize a single set of significant impact runs for comparison to the modeling significance levels for both $PM_{2.5}$ and PM_{10}.

For the model runs used to determine significant impacts for $PM_{2.5,}$ Case 9 for the five turbines (50% load, 108º F ambient temperature) yielded the highest overall impacts for each of the five years of meteorology. Using the Case 9 results, the highest modeled 24-hour impacts at each receptor were averaged over the five years of meteorological data, as recommended by the 3/23/10 EPA memo titled *Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS*. Those receptors for which this 5-year average exceeded the significant impact level of 1.2 µg/m^3 were used as the receptor grid for the cumulative impact model runs for the 24-hour averaging period. Similarly, the modeled annual impacts were averaged across the five years of meteorology to determine which receptors would yield predicted impacts above the modeling significance level of 0.3 µg/m^3.

On October 20, 2010, the EPA published a final rule regarding PSD increments and significant impact levels for $PM_{2.5}$ (75 Fed. Reg. 64,864). This rule established the "major source baseline date" for $PM_{2.5}$ as October 20, 2010, and the "trigger date" for $PM_{2.5}$ as October 20, 2011. The "minor source baseline date" is the earliest date after the trigger date on which a source submits the first complete PSD application in a particular area. Once the minor source baseline date is established, emissions increases from all sources, including those in the permit application for the CPGS, consume a portion of the PSD increment in that area. The PSD application for the CPGS was deemed complete on March 1, 2012, which established the minor source baseline date for $PM_{2.5}$ in the area. The predicted areas of significant impact for 24-hour and annual $PM_{2.5}$ extend into property belonging to both the City of Cheyenne and Laramie County, and therefore trigger the minor source baseline date for both areas. All sources associated with the CPGS are therefore increment-consuming for the City of Cheyenne and Laramie County.

For the cumulative model runs, all sources of $PM_{2.5}$ emissions from the CPGS and outside sources of $PM_{2.5}$ were modeled to determine if operation of the CPGS would exceed the WAAQS/NAAQS or PSD increments. Based on the results of the significant impact modeling, the five combustion turbines were input to the model runs using the Case 9 configuration (50% load, 108º F ambient temperature). Background concentrations (see Table 9-7), which represent all sources not explicitly modeled, were added to the maximum modeled impacts to arrive at total predicted impacts for comparison to the NAAQS/WAAQS. Because of a lack of information on the $PM_{2.5}$ emission rates for the outside sources, the PM_{10} emissions for those sources were conservatively assumed to equal $PM_{2.5}$.

Current EPA guidance for modeling compliance with the 24-hour $PM_{2.5}$ NAAQS requires that the highest overall modeled 24-hour impact be added to an appropriate background concentration. The resulting sum should then be compared to the NAAQS (3/23/2010 EPA memo). The monitored background 24-hour concentration is based on the form of the 24-hour NAAQS, i.e., the 3-year average of the 98th percentile 24-hour averages. Table 9-9 presents a summary of the results of the $PM_{2.5}$ modeling, which are below the NAAQS/WAAQS and the PSD increments.

Table 9-9: Results of Cumulative Modeling for $PM_{2.5}$

Averaging Time	Year	Modeled Impact (µg/m³)	PSD Increment (µg/m³)	Background Concentration (µg/m³)	Total Modeled Impact (µg/m³)	WAAQS/NAAQS (µg/m³)
24-Hour	2008-2012	4.9*	9.0	12.0	16.9	35
Annual	2008	1.04	4	3.2	4.24	15
	2009	0.97			4.17	
	2010	1.05			4.25	
	2011	1.09			4.29	
	2012	1.10			4.30	

*98th percentile average of the maximum modeled 24-hour averages across the 5 years of meteorological data.

9.2.6 Particulate Matter (PM_{10})

The Division was able to use the NAAQS model runs for $PM_{2.5}$ to also represent the expected impacts of PM_{10} because: 1) the expected $PM_{2.5}$ emissions from the CPGS sources are equal to the expected PM_{10} emissions, 2) a similar assumption (PM_{10} emissions = $PM_{2.5}$ emissions) was used for the outside sources, and 3) the predicted area of significant impact for PM_{10} was contained within the predicted impact area for $PM_{2.5}$. The significant impact modeling runs showed that the predicted impacts from the CPGS would be below the modeling significance level of 1.0 µg/m³ for annual PM_{10}. For the 24-hour averaging period, only a few receptors yielded a predicted impact above the significance level of 5.0 µg/m³. Table 9-10 presents a summary of the cumulative modeling results for PM_{10}.

Table 9-10: Results of Cumulative Modeling for PM_{10}						
Averaging Period	Year	Modeled Impact (µg/m³)*	PSD Increment (µg/m³)	Background Concentration (µg/m³)	Total Predicted Impact (µg/m³)	WAAQS/NAAQS (µg/m³)
24-Hour	2008	6.7	30	46.3	53.0	150
	2009	8.0			54.3	
	2010	7.7			54.0	
	2011	6.5			52.8	
	2012	7.3			53.6	

* Modeled impacts represent overall highest 2nd-high predicted concentration

9.2.7 Ozone

Because ozone is a pollutant that forms due to emissions from a large number of sources over larger (regional) areas, modeling to demonstrate compliance with the ozone NAAQS is not typically performed for single facilities, and was not performed for the proposed CPGS. To assess the potential impact of the project on local ozone levels, ozone monitoring data was examined to determine the current ambient levels, and the expected emissions of ozone precursors from the CPGS were compared to county-wide levels of the same pollutants.

An ozone monitor has been operating since January of 2011 in Cheyenne, approximately five miles northwest of the CPGS. This monitoring station is part of the EPA's NCore Monitoring Network. Table 9-11 presents a summary of ozone data collected at the Cheyenne NCore site through calendar year 2014. As shown in the table, monitored ozone levels at the Cheyenne NCore site are below the 8-hour NAAQS for ozone.

Table 9-11: NCore Ozone Data for Cheyenne, WY		
Year	4th Highest 8-Hour Daily Maximum Concentration (ppb)	8-Hour NAAQS (ppb)
2012	68	75
2013	69	
2014	65	

The applicant also compared the expected emission of ozone precursors, NO_x and volatile organic compounds (VOCs), to the county-wide emissions for Laramie County. As shown in Table 9-12, the expected emissions from the CPGS represent a small fraction of the county-wide emissions, and the Division does not expect the project to threaten the ozone NAAQS.

Table 9-12: Laramie County Emissions of Ozone Precursors vs. CPGS Emissions		
Category	**NO_x (tpy)**	**VOC (tpy)**
CPGS Projected Emissions	153.1	76.8
Laramie County Total*	7,986	4,290
% of County-Wide Total (from proposed CPGS)	1.9%	1.8%

* Source: NEI 2008 v1.5 GPR
(http://www.epa.gov/air/emissions/index.htm)

10.0 PROJECTED IMPACT ON CLASS I AREA AIR QUALITY

10.1 Scope of Analysis

Congress has designated particular areas for the highest level of air-quality protection. These areas, known as "Class I" areas, include larger national parks/wilderness areas that were in existence in 1977. The Federal Land Managers (FLMs) are given, through the PSD title of the Clean Air Act, a role in the protection of Class I areas from air quality impairment due to man-made air pollution.

A workgroup consisting of representatives from the three FLMs that manage the 158 Federal Class I areas has developed a guidance document for assessing the impact of PSD sources on Class I areas. This workgroup, called the *Federal Land Managers' Air Quality Related Values Work Group* (FLAG), released a revised version of their *Phase I Report* in late 2010. The 2010 FLAG document describes a screening procedure to identify sources that would be considered to have negligible impact on Class I area air quality related values (AQRVs). According to the 2010 FLAG document, the total emissions of visibility-reducing pollutants from a source should be expressed in tons per year, as based on 24-hour maximum allowable emissions of SO_2, NO_x, PM_{10}, and H_2SO_4. The total emissions (Q) are then divided by the distance (in km) from Class I areas (D). If Q/D is 10 or less, the FLM would likely not request a Class I area AQRV impact analyses from that source.

Black Hills Power, Inc. provided Q/D calculations for the CPGS to the National Park Service (NPS) that indicated that the Q/D for the nearest Class I area, Rocky Mountain National Park in Colorado, would be less than 10. An e-mail from the NPS to the Division dated August 24, 2011 indicated that the NPS would not require an AQRV analysis for the project. In particular, the original permit application for the station estimated that annual station-wide totals of visibility-reducing pollutants (NO_x, SO_2, and PM_{10}) would be approximately 350 tpy. The nearest Class I area to the station is Rocky Mountain National Park in Colorado, located at a distance of 93 km. The calculated Q/D for the initial project was therefore 3.8, well below the Q/D ratio of 10 recommended by the 2010 FLAG.

The determination by the NPS that Black Hills Power, Inc. did not have to perform an AQRV analysis for the project pertained specifically to analyses for Class I area visibility and acid deposition, but not to Class I area PSD increments. Chapter 6, Section 4(b)(i)(A)(I) of the WAQSR requires that the predicted impacts in Class I areas from any major stationary source be below the Class I PSD increments. Therefore, the Division required Black Hills Corporation to demonstrate that the proposed project would not threaten the Class I area PSD increments. The demonstration for the initial permit for the project was conducted with the EPA's CALPUFF modeling system, which is the EPA-preferred model for long-range transport. Black Hills Power, Inc. used the results of the initial CALPUFF modeling, along with an evaluation of the expected emissions from the auxiliary boiler, to demonstrate that Class I area increments would remain protected with operation of the CPGS, as described in the following section.

10.2 Demonstration

Guidance published in the Federal Register (Vol. 61, No. 142, July 1996) by the U.S. EPA established a method to determine if a new source had a significant ambient impact on a Class I area. This guidance introduced a set of Class I area Significant Impact Levels (SILs) to be used as the metric for assessing the ambient impacts at Class I areas. In the proposed rules, a new source or proposed modification which can be shown, using air quality models, to have ambient impacts below the Class I SILs for a given pollutant/averaging period would not be required to conduct a cumulative Class I increment consumption analysis for that pollutant/averaging period.

In the initial Class I area significant impact analysis for the CPGS, CALPUFF modeling demonstrated that maximum predicted concentrations from the project would be below the Class I SILs for each pollutant at each Class I area that was analyzed. Table 10-1 presents a summary of the results of the initial CALPUFF modeling for the project (CT-12636), a comparison of the emissions rates used for the initial CALPUFF modeling vs. the expected change in emissions due to the proposed modification, and the percent increase in emissions represented by the modification. Table 10-1 shows that the impacts from the station, even with the proposed modification, would remain below the Class I SILs. Based on this analysis, the operation of the CPGS will not threaten the Class I PSD increments.

Table 10-1: Class I Area Impact Demonstration								
CALPUFF Results for CT-12636								
Class I Area	**Annual NO_2**	**3-hour SO_2**	**24-Hour SO_2**	**Annual SO_2**	**24-Hour PM_{10}**	**Annual PM_{10}**	**24-Hour $PM_{2.5}$**	**Annual $PM_{2.5}$**
Mt. Zirkel WA	0.0002	0.002	0.0006	0.00001	0.007	0.0001	0.007	0.0001
Rawah WA	0.0007	0.004	0.001	0.00003	0.016	0.0004	0.016	0.0004
Rocky Mtn. Nat. Park	0.0017	0.008	0.0026	0.00007	0.041	0.001	0.041	0.001
Savage Run WA	0.0004	0.002	0.0009	0.00002	0.013	0.0003	0.013	0.0003
Class I Significance Levels	**0.1**	**1.0**	**0.2**	**0.1**	**0.3**	**0.2**	**0.07**	**0.06**
Class I PSD Increments	**2.5**	**25**	**5**	**2**	**8**	**4**	**2**	**1**

Comparison of Modeled Emissions			
Pollutant	NO_2	SO_2	$PM_{10}/PM_{2.5}$
CALPUFF Emission Rates (station total lb/hr) for MD-12636	129.2	2.6	21.8
Proposed Emissions (lb/hr)	127.41	2.5	23.26
Change in Emissions(lb/hr)	-1.79	-0.1	1.46
Percent Increase	0.0%	0.0%	6.7%

11.0 PROPOSED PERMIT CONDITIONS

The Division proposes to issue an air quality permit to Black Hills Power, Inc. for the modification of the Cheyenne Prairie Generating Station with the following permit conditions:

General Conditions

1. That authorized representatives of the Division of Air Quality be given permission to enter and inspect any property, premise or place on or at which an air pollution source is located or is being constructed or installed for the purpose of investigating actual or potential sources of air pollution and for determining compliance or non-compliance with any rules, standards, permits or orders.

2. That all substantive commitments and descriptions set forth in the application for this permit, unless superseded by a specific condition of this permit, are incorporated herein by this reference and are enforceable as conditions of this permit.

3. That Black Hills shall obtain an Operating Permit in accordance with Chapter 6, Section 3 of the WAQSR.

4. That all notifications, reports and correspondence required by this permit shall be submitted to the Stationary Source Compliance Program Manager, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002 and a copy shall be submitted to the District Engineer, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002. Submissions may also be done electronically through https://airimpact.wyo.gov to satisfy requirements of this permit

5. That written notification of the anticipated date of initial startup, in accordance with Chapter 6, Section 2(i) of the WAQSR, is required not more than 60 days or less than 30 days prior to such date. Notification of the actual date of startup is required within 15 days after startup.

6. That the date of commencement of construction shall be reported to the Administrator within 30 days of commencement. In accordance with Chapter 6, Section 2(h) of the WAQSR, approval to construct or modify shall become invalid if construction is not commenced within 24 months after receipt of such approval or if construction is discontinued for a period of 24 months or more. The Administrator may extend the period based on satisfactory justification of the requested extension.

7. That performance tests be conducted, in accordance with Chapter 6, Section 2(j) of the WAQSR, within 30 days of achieving a maximum design rate but not later than 90 days following initial startup, and a written report of the results be submitted. The operator shall provide 15 days prior notice of the test date. If a maximum design rate is not achieved within 90 days of startup, the Administrator may require testing be done at the rate achieved and again when a maximum rate is achieved.

8. That Black Hills Power, Inc. shall retain, at the Cheyenne Generating Station, records of the daily inspections, monthly observations, preventative maintenance records, and support information as required by this permit for a period of at least five (5) years from the date such records are generated and the records shall be made available to the Division upon request.

9. That Black Hills shall comply with the acid rain program regulations in Chapter 11, Section 2 of the WAQSR.

10. That the authorization to construct the three (3) inlet air chillers, two (2) fuel gas heaters, and one (1) of the inlet air heaters under air quality permit CT-12636 shall be revoked upon notification of commencement of construction under this permit.

Turbine Conditions

11. Initial performance testing, as required by Condition 7 of this permit shall be conducted on the following sources:

    i. Combustion Turbines (EGU004-EGU005) for compliance with limits defined in Condition 12:

    NO_x Emissions: Compliance testing for NO_x shall be conducted using EPA Reference Methods 1-4, 7E, and the requirements of 40 CFR, Part 60, Subpart KKKK. Compliance with the lb/hr emission limits shall be determined with three (3) 1-hour tests conducted while the turbine is operating near full load.

    CO Emissions: Compliance testing for CO shall be conducted using EPA Reference Methods 1-4, and 10. Compliance with the lb/hr emission limits shall be determined with three (3) 1-hour tests conducted while the turbine is operating near full load.

    VOC Emissions: Compliance tests shall consist of three (3) 1-hour tests following EPA Reference Methods 1-4 and 25 or a Division approved equivalent reference method.

    $PM/PM_{10}/PM_{2.5}$ Emissions: Compliance tests shall consist of three (3) 1-hour tests following EPA Reference Methods 1-4, 5, and 202.

    Opacity: Opacity testing shall consist of three (3) 6-minute averages of the opacity as determined by Method 9 of 40 CFR part 60, Appendix A.

Ammonia Emissions: Compliance tests shall consist of three (3) 1-hour tests following EPA Reference Methods 1-4 and CTM-027 or a Division approved equivalent test method.

A test protocol shall be submitted for review and approval prior to testing. Notification of the test date shall be provided to the Division fifteen (15) days prior to testing. Results shall be submitted to this Division within 45 days of completion.

12. Effective on and after the date on which the performance test is conducted, as required by Condition 7 of this permit, emissions from the combined cycle combustion turbines (EGU004-EGU005) equipped with SCR and an oxidation catalyst shall be limited to the rates in the table below. These limits apply during all operating periods, except that the ppm at 15% O_2 and lb/hr NO_x and CO limits do not apply during periods of startup and shutdown as defined in Condition 13.

Pollutant	Concentration	lb/hr
GE LM6000 PF		
NO_x	3 ppm_v at 15% O_2 (1-hour average)	4.6 (30-day rolling average)
CO	4 ppm_v at 15% O_2 (1-hour average)	3.7 (30-day rolling average)
VOC [1]	3 ppm_v at 15% O_2	3.0
$PM/PM_{10}/PM_{2.5}$ [1] (Filterable + Condensable)	--	4.0
Ammonia [1]	10 ppm_v at 15% O_2	5.7
GE LM6000 PF+		
NO_x	3 ppm_v at 15% O_2 (1-hour average)	5.3 (30-day rolling average)
CO	4 ppm_v at 15% O_2 (1-hour average)	4.3 (30-day rolling average)
VOC [1]	3 ppm_v at 15% O_2	3.4
$PM/PM_{10}/PM_{2.5}$ [1] (Filterable + Condensable)	--	4.0
Ammonia [1]	10 ppm_v at 15% O_2	6.5

[1] Averaging period is defined by the performance testing in condition 9.

13. That the combined cycle combustion turbines (EGU004-EGU005) shall be limited to the following during periods of startup and shutdown. These limits apply during any hour where a startup and/or shutdown have occurred.

i. Startup begins when combustion starts as detected by the Fireye (i.e., the turbine flame detection system) in the combustion turbine and ends when 40 minutes has elapsed.

ii. Shutdown begins when the operator initiates the shutdown of the turbine and ends when fuel is no longer being introduced into the combustion turbine.

iii. Black Hills shall keep records that include the date of each startup and/or shutdown, time of occurrence, and duration of each startup and/or shutdown.

iv. Exceedances associated with startup and shutdown of the combined cycle combustion turbines as a result of a sudden and unforeseen failure or malfunction are not exempted by this permit. Unavoidable equipment malfunctions are addressed in Chapter 1, Section 5 of the WAQSR.

v. Emissions from each combined cycle combustion turbine shall be limited to the rates in the table below during periods of startup and shutdown. The mass emission limit will apply to any hour in which a startup and/or shutdown occurs.

Pollutant	lb/hr
GE LM6000 PF	
NO_x	22.5
CO	56.5
GE LM6000 PF+	
NO_x	23.9
CO	47.8

vi. Black Hills shall not exceed a total of 1200 hours of startup/shutdown operation per calendar year for the combined cycle combustion turbines (EGU004-EGU005).

14. During periods of combustion tuning and testing, emissions of NO_x and CO from each affected GE LM6000 PF turbine shall not exceed 25 ppm at 15% O_2 and 70 ppm at 15% O_2, on a 1-hour average, respectively. Use of the NO_x and CO emission limit for purposes of combustion tuning and testing shall not exceed a total of 240 hours in any calendar year for all five turbines combined. Records of the number of hours each turbine undergoes combustion tuning and testing shall be recorded and maintained.

15. During periods of combustion tuning and testing, emissions of NO_x and CO from each affected GE LM6000 PF+ turbine shall not exceed 25 ppm at 15% O_2 and 25 ppm at 15% O_2, on a 1-hour average, respectively. Use of the NO_x and CO emission limit for purposes of combustion tuning and testing shall not exceed a total of 240 hours in any calendar year for all five turbines combined. Records of the number of hours each turbine undergoes combustion tuning and testing shall be recorded and maintained.

16. That the combined cycle combustion turbines (EGU004-EGU005) shall be limited to natural gas as a fuel.

17. That the opacity from the combined cycle combustion turbines (EGU004-EGU005) shall be limited to twenty percent (20%) opacity as determined by Method 9 of 40 CFR part 60, Appendix A.

18. Black Hills Power, Inc. shall use the following continuous emission monitoring (CEM) equipment on the combined cycle combustion turbines (EGU004-EGU005) to demonstrate continuous compliance with the emission limits set forth in this permit:

i. Install, calibrate, operate, and maintain a monitoring system, and record the output, for measuring NO_x emissions discharged to the atmosphere in ppm_v and lb/hr. The NO_x monitoring system shall consist of the following:

a. A continuous emission NO_x monitor located in the combustion turbine exhaust stack.

b. A continuous flow monitoring system for measuring the flow of exhaust gases discharged into the atmosphere or a fuel flow monitor meeting the requirements of 40 CFR part 75, appendix D, and 40 CFR part 60, subpart KKKK.

c. A continuous oxygen or carbon dioxide monitor at the location NO_x emissions are monitored.

ii. Install, calibrate, operate, and maintain a monitoring system, and record the output, for measuring CO emissions discharged to the atmosphere in ppm_v and lb/hr. The CO monitoring system shall consist of the following:

a. A continuous emission CO monitor located in the combustion turbine exhaust stack.

b. A continuous flow monitoring system for measuring the flow of exhaust gases discharged into the atmosphere or a fuel flow monitor meeting the requirements of 40 CFR part 75, appendix D, and 40 CFR part 60, subpart KKKK.

c. A continuous oxygen or carbon dioxide monitor at the location CO emissions are monitored.

iii. Each continuous monitor system listed in this condition shall comply with the following:

a. 40 CFR part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.

b. Monitoring requirements of Chapter 5, Section 2(j) of the WAQSR including the following:

1. 40 CFR part 60, Appendix B, Performance Specification 2 for NO_x, Performance Specification 4 or 4A for CO, and Performance Specification 3 for O_2 and CO_2. The monitoring systems must demonstrate linearity in accordance with Division requirements.

2. Quality Assurance requirements of Appendix F, 40 CFR part 60 unless otherwise specified in an applicable subpart (Subpart KKKK) or by the Administrator.

3. Black Hills Power, Inc. shall develop and submit for the Division's approval a Quality Assurance plan for the monitoring systems listed in this condition within 90 days of initial startup.

19. Following the initial performance tests, as required by Condition 7 of this permit, compliance with the limits set forth in this permit shall be determined with data from the continuous monitoring systems required by Condition 18 of this permit as follows:

i. Exceedance of the limits shall be defined as follows:

a. Any 1-hr average calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment required in Condition 18 which exceeds the ppm_v limits established for NO_x and CO in this permit. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j).

b. Any 30-day rolling average which exceeds the lb/hr NO_x or CO limit as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n} (C)_h}{n}$$

Where:

E_{avg} = 30-day rolling average emission rate (lb/hr).

C = 1-hour average NO_x or CO emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate or average hourly fuel flow) from the CEM equipment required by Condition 18. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours in the last 30 successive turbine operating days with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "turbine operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which fuel is combusted at any time in the turbine.

ii. Black Hills Power, Inc. shall comply with all reporting and record keeping requirements as specified in Chapter 5, Section 2(g) of the WAQSR. Excess NO_x and CO emissions shall be reported in units of ppm_v and lb/hr.

20a. That annually, or as otherwise specified by the Administrator, the combustion turbines (EGU004-EGU005) shall be tested to verify compliance with the VOC, $PM/PM_{10}/PM_{2.5}$ and ammonia limits set forth in this permit. The first annual test is required the following calendar year after completion of the initial performance test. Testing for VOC, $PM/PM_{10}/PM_{2.5}$ and ammonia shall be conducted following EPA Reference Methods. A test protocol shall be submitted for review and approval prior to testing. Notification of the test date shall be provided to the Division fifteen (15) days prior to testing. Results shall be submitted to this Division within 45 days of completion.

20b. The Air Quality Division shall be notified within 24 hours of any emission unit where the testing/monitoring required by 20(a) of this condition shows operation outside the permitted emission limits. By no later than 7 calendar days of such testing/monitoring event, the owner or operator shall repair and retest/monitor the affected emission unit to demonstrate that the emission unit has been returned to operation within the permitted emission limits. Compliance with this permit condition regarding repair and retesting/monitoring shall not be deemed to limit the authority of the Air Quality Division to cite the owner or operator for an exceedance of the permitted emission limits for any testing/monitoring required by 20(a) of this condition which shows noncompliance.

21. That Black Hills Power, Inc. shall comply with all of the applicable requirements of 40 CFR part 60, subpart KKKK for the combined cycle combustion turbines (EGU004-EGU005).

Cooling Tower

22. That Black Hills shall utilize drift eliminators with a drift rate no greater than 0.0005% on the cooling tower (CTW016).

Auxiliary Boiler

23. Initial performance testing, as required by Condition 7 of this permit shall be conducted on the following sources:

    i. Auxiliary Boiler (BOL008):

    NO_x Emissions: Compliance tests shall consist of three (3) 1-hour tests following EPA Reference Methods 1-4 and 7E.

    CO Emissions: Compliance tests shall consist of three (3) 1-hour tests following EPA Reference Methods 1-4 and 10.

    A test protocol shall be submitted for review and approval prior to testing. Notification of the test date shall be provided to the Division fifteen (15) days prior to testing. Results shall be submitted to this Division within 45 days of completion.

24. Emissions from the Auxiliary Boiler equipped with low NO_x burners and flue gas recirculation shall be limited to the following and shall apply at all times:

ID	Source	NO_x			CO		
		lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy
BOL008	Auxiliary Boiler	0.0175	0.4	1.9	0.0375	0.9	4.1

25a. That annually, or as otherwise specified by the Administrator, the Auxiliary Boiler (BOL008) shall be tested to verify compliance with the NO_x and CO limits set forth in this permit. The first annual test is required the following calendar year after completion of the initial performance test. Testing for NO_x and CO shall be conducted following EPA reference methods. A test protocol shall be submitted for review and approval prior to testing. Notification of the test date shall be provided to the Division fifteen (15) days prior to testing. Results shall be submitted to this Division within 45 days of completion.

25b. The Air Quality Division shall be notified within 24 hours where the testing/monitoring required by 25(a) of this condition shows operation outside the permitted emission limits. Black Hills Power, Inc. shall repair and retest/monitor the affected emission unit to demonstrate that the emission unit has been returned to operation within the permitted emission limits. Compliance with this permit condition regarding repair and retesting/monitoring shall not be deemed to limit the authority of the Air Quality Division to cite the owner or operator for an exceedance of the permitted emission limits for any testing/monitoring required by 25(a) of this condition which shows noncompliance.

26. That the Auxiliary Boiler (BOL008) shall be limited to pipeline quality natural gas as a fuel.

27. That Black Hills Power, Inc. shall comply with all of the applicable requirements of 40 CFR part 60, subpart Dc for the Auxiliary Boiler (BOL008).