OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **June 15, 2021**

TO: Phillip Fielder, P.E., Chief Engineer

THROUGH: Eric L. Milligan, P.E., Engineering Manager, Engineering Section

THROUGH: Joseph K. Wills, P.E., Engineering Section

FROM: Anne Smith, P.E., New Source Permits Section

SUBJECT: Evaluation of Permit Application No. **2014-1728-C (M-4) PSD**
Grand River Dam Authority (GRDA)
Grand River Energy Center (SIC 4911, NAICS 221112)
Facility ID: 799
Latitude 36.19332°N; Longitude: 95.28475°W; (Main Entrance)
Sections 20, 21, 28 & 29, Township 20N, Range 19E, Mayes County, OK
Directions: The facility is located three miles east of Chouteau on Hwy 412, then one mile north on Hwy 412B.

SECTION I. INTRODUCTION

GRDA submitted an application for modification of Permit No. 2009-179-C (M-5) and the Prevention of Significant Deterioration (PSD) analysis of construction Permit No. 2009-179-C (M-2) PSD for their Grand River Energy Center on February 8, 2019. The facility is currently operating under Part 70 Operating Permit No. 2014-1728-TVR3 (M-3), issued on May 8, 2019. GRDA has requested the following changes (see Section III of this Memorandum for details):

a. Revision of the carbon monoxide (CO) emission factor for Wall Boiler Unit 2 (B-02-2) from 0.17 lb/MMBtu to 0.27 lb/MMBtu.
b. Removal of Wall Boiler Unit 1 (B-02-01) and Fuel Gas Heater (B-02-6).
c. Limit the hours of operation for Auxiliary Boiler No. 3 (B-02-5) to less than 10% of the annual capacity.
d. Add clarification for the method used to determine the emission equivalent hours of operation for Auxiliary Boilers No. 1, 2, and 3 (B-02-3, B-02-4, and B-02-5).
e. Incorporate the following Specific Conditions updates authorized in the Part 70 Operating Permit No. 2014-1728-TVR3 (M-3):
   i) Increased hours of operation for Auxiliary Boiler No. 1 (B-02-3) and Auxiliary Boiler No. 2 (B-02-4);
   ii) Conversion to natural gas of Auxiliary Boiler No. 1 (B-02-3) and Auxiliary Boiler No. 2 (B-02-4); and

ii) Removal of Loaded and Empty S-Sorb truck delivery (VT-07-01 and VT-07-02) and Loaded and Empty MerSorb truck delivery (VT-08-01 and VT-08-02) emissions from Truck & Maintenance Vehicle Traffic and Material Storage.

The facility is a PSD major source and a major source of HAP.

SECTION II. FACILITY DESCRIPTION

The Grand River Energy Center is an electric generating station that consists of one coal-fired Foster Wheeler opposed Wall Boiler Unit 2 (B-02-2), and a natural gas-fired combined cycle combustion Turbine Unit 3 (T-01-1). GRDA retired Wall Boiler Unit 1 (B-02-1) in December 2020. Fuel Gas Heater (B-02-6), used for the conversion of Wall Boiler Unit 1 (B-02-1) to natural gas, was also retired in December 2020. Wall Boiler Unit 2 (B-02-2) was built in 1982, has a rated capacity of 520 MW, and is designed to burn Wyoming coal or a blend of Wyoming and bituminous (Oklahoma) coal. The air pollution control equipment on Wall Boiler Unit 2 (B-02-2) consists of a powdered activated carbon (PAC) injection system, a flue gas desulfurization (FGD) system with a spray dryer absorber (SDA), and a pulse jet fabric filter (PJFF) system. The main boiler igniter in Wall Boiler Unit 2 (B-02-2) is natural gas-fired. Turbine Unit 3 (T-01-1) is a Mitsubishi Heavy Industries (MHI), Model M501J and includes a combustion turbine generator (CTG), a duct-fired heat recovery steam generator (HRSG), and a steam turbine generator (STG). The CTG is designed to operate only in combined cycle mode and has a total heat input of 4,160.9 MMBTUH and an output of 495 megawatts (net). Turbine Unit 3 (T-01-1) only fires commercial grade natural gas.

Coal is delivered to the site by truck and by rail. The Wyoming coal is received in “unit trains.” The Oklahoma coal, is received in trucks. Wall Boiler Unit 2 (B-02-2) is designed to burn a 90%/10% mix of Wyoming/Oklahoma coal, with the ratio based on heat input. Wall Boiler Unit 2 (B-02-2) may operate on 100% Wyoming coal. Unit trains go through the rotary dumper, which empties each car by turning it upside down. Similar equipment, including conveyors, towers, and other typical handling equipment process both types of coal. A stacker/reclaimer either puts the coal onto a particular pile (stacking), or takes it from a pile for use in the boiler (reclaiming). Reclaimed coal is temporarily stored in bins.

The PAC injection system for Wall Boiler Unit 2 (B-02-2) injects sorbent upstream of both the SDA and the PJFF system to remove mercury and mercury compounds that are released from the coal into the flue gas during the combustion process. PAC particles adsorb mercury and then are collected in the PJFF system and removed with the fly ash waste. PAC is received in bulk by truck and unloaded pneumatically into one of two storage silos. The trucks are equipped with their own pneumatic unloading system but a secondary PAC conveying air blower is also used. PAC is fed from the silo by rotary feeders into a volumetric feeder hopper where it is temporarily stored. During the loading/unloading process of the PAC silos, the silos are vented through a bin vent filter that controls and collects particulate matter. The PAC is distributed to an array of injection lances, whose locations are optimized for the flow of flue gas in the ductwork upstream of the SDA system.

The FGD system on Wall Boiler Unit 2 (B-02-2) uses lime. Lime is received via trucks and pneumatically transferred to storage silos. There is no crushing or grinding of the material before use. Lime is also pneumatically transferred from the storage silos to the FGD system.

The PJFF baghouse dust collector captures fly ash, SDA byproduct material, unused lime reagent, and PAC. Collected particulate forms a cake on the bag, enhancing the bag's filtering efficiency. The pressure drop across the bags increases as the thickness of the dust cake increases. At a predetermined pressure drop set point, the filtering bags are cleaned, dislodging a large portion of the dust cake. Dislodged dust cake is stored in the PJFF hopper and is pneumatically conveyed to the ash silos.

The two natural gas-fired Auxiliary Boilers No. 1 and 2 (B-02-3 & B-02-4) were installed for start-up of Wall Boiler Unit 2 (B-02-2). These auxiliary boilers operate occasionally to assure that they are still in good condition and to supply steam to plant auxiliary equipment and plant heating, as necessary. A third natural gas-fired Auxiliary Boiler No. 3 (B-02-5) provides start-up steam for Turbine Unit 3 (T-01-1). Operation of the natural-gas fired auxiliary boilers are limited to an emission equivalent of 2,760 hours per 12-month period each for B-02-3 and B-02-4, and 876 hours per 12-month period for B-02-5 at full load. The emission equivalent hours of operation for each unit is calculated as a sum of the hours of operation multiplied by the ratio of the actual heat input for each hour of operation to the permitted heat input at full load as indicated below.

$$\text{Emission Equivalent Hours of Operation} = \sum_{i=1}^{N} 1\,Hr\left(\frac{Actual\ HI_i}{Permit\ HI}\right)$$

Where:

N = Operating hours for each 12-month period
1 Hr = One hour of operation
Actual HI_i = Actual Heat Input at hour i
Permit HI = Permit Heat Input at full load

A new linear, mechanical draft, cooling tower (LMDCT) and a new inlet air chiller were installed to support Turbine Unit 3 (T-01-1). The new LMDCT is comprised of approximately seven cells to dissipate waste heat from the boiler's steam cycle. Makeup water to the cooling tower is supplied from surface waters (Grand Neosho River). During the cooling process, small water droplets, known as cooling tower drift, escape to the atmosphere through the cooling tower exhaust. To minimize this effect, the cooling tower is equipped with drift eliminators, at the industry standard design drift rate of 0.0005 percent of the circulating water flow rate. The drift eliminators provide multiple directional changes of airflow that helps prevent the escape of water droplets. Dense air improves the efficiency of the CTG, so the inlet air for the unit is cooled utilizing chillers. A small cooling tower was incorporated to provide the necessary cooling to the chillers used in the inlet air cooling system for Turbine Unit 3 (T-01-1). The cooling tower is equipped with drift eliminators, at a design rate of 0.0005 percent of the circulating water flow rate.

In the event of loss of the GRDA 345 kV substation or the connecting 345 kV transmission system, AC power required for a safe shutdown of Turbine Unit 3 (T-01-1) is supplied by the 2 MW emergency generator (EG-03-3) fired with ultra-low sulfur diesel. The emergency generator will typically be tested for approximately 1 to 2 hours per week to confirm its ready-to-start condition. The permit limits operation of the emergency generator (EG-03-3) to no more than 100 hours per year for normal testing and maintenance. Operation of the emergency generator (EG-03-3) is not limited in the event of an actual emergency.

SECTION III. PROJECT DESCRIPTION

On September 16, 2016, ODEQ's Rhoda Jeffries, Environmental Programs Manager, conducted a Partial Compliance Evaluation (PCE). As a result, additional Continuous Emission Monitoring System (CEMS) data was requested to determine compliance status of Wall Boiler Unit 1 & 2 (B-02-1 and B-02-2). Based on the information received, GRDA operated in noncompliance with Specific Condition No. 1 of Permits No. 2014-1728-TVR3, 2009-179-C (M-5), 2009-179-C (M-4), 2009-179-C (M-3), and 2009-179-C (M-2) PSD by failing to limit the CO emissions from Wall Boiler Unit 2 (B-02-2) to less than 0.17 lb/MMBtu (30-day rolling average) for 169 days in 2013, 114 days in 2014, and 21 days in 2016.

Therefore, GRDA has requested to revise the CO emission factor for Wall Boiler Unit 2 (B-02-2) from 0.17 lb/MMBtu to 0.27 lb/MMBtu. The original CO emission limit for Wall Boiler Unit 2 (B-02-2) was based on a one-time steady state performance test and no safety factor was added. Since the current permit limit for CO is based on a BACT limit (lb/MMBtu), GRDA is required to address the applicable aspects of PSD review for Wall Boiler Unit 2 (B-02-2). The PSD review for Wall Boiler Unit 2 (B-02-2) is detailed in Section VII of this Memorandum.

GRDA also requested to have the removal of Wall Boiler Unit 1 (B-02-1), the removal of the Fuel Gas Heater (B-02-6), and the changes made in Permit No. 2014-1728-TVR3 (M-3) incorporated into this permit.

SECTION IV. PERMITTING HISTORY

The proposed relaxation of an existing permit condition requires a review of the facility's permitting history:

Permit No. 2014-1728-TVR3 (M-3); Issued May 8, 2019; Minor modification to convert Auxiliary Boilers No. 1 & 2 from distillate fuel oil to natural gas. This permit also incorporated changes requested in the applications for Permits No. 2014-1728-TVR3 (M-2) and 2014-1728-TVR3 (M-1) which were withdrawn upon issuance of Permit No. 2014-1728-TVR3 (M-3). The requested changes included a minor modification to increase the permitted limit on hours of operation of Auxiliary Boilers No. 1 & 2 from 400 hours/yr to 2,760 hours/yr, each. This permit also incorporated the changes made in Permit No. 2009-179-C (M-5).

Permit No. 2009-179-C (M-5); Issued May 17, 2017; Administrative amendment to Permit No. 2009-179-C (M-4) makes changes to Specific Condition No. 1 and 2. The change to Specific Condition No. 1 was made to clarify that after construction of Turbine Unit 3, Wall Boiler Unit 1 shall be limited to 2,952 hours of operation on natural gas or the expected emissions from operation at full load for 2,952 hours on natural gas. The change made to Specific Condition No. 2 was to clarify the intended requirements to demonstrate compliance before, during, and after the construction projects authorized in Permit No. 2009-179-C (M-4).

Permit No. 2009-179-C (M-4); Issued May 10, 2016; Minor modification to remove the combined annual limit for natural gas usage in Wall Boiler Units 1 & 2. This permit also incorporated changes authorized by Permit No. 2009-179-C (M-3).

Permit No. 2014-1728-TVR3; Issued March 17, 2015; Third Title V renewal permit which incorporated the changes authorized in Permit No. 2009-179-C (M-3).

Permit No. 2009-179-C (M-3); Issued August 21, 2014; Construction permit authorizing construction of the MATS pollution control project for Wall Boiler Unit 2, the conversion of Wall Boiler Unit 1 to fire natural gas, and the installation of a natural gas-fired combined cycle combustion Turbine Unit 3. The CO emissions from Turbine Unit 3 were offset only by reductions from Wall Boiler Unit 1. Therefore, the CO emission increases from Wall Boiler Unit 2 do not affect that project.

Permit No. 2009-179-C (M-2) PSD; Issued August 1, 2012; Permit modification to install low-NO_X burners and overfire air on Wall Boiler Units 1 & 2. This permit established the CO emission limit of 0.17 lb/MMBtu (30-day rolling average) for Wall Boiler Unit 2 based on a BACT.

SECTION V. EQUIPMENT

EUG 1 Entire Facility

This EUG is established to cover all rules or regulations that apply to the facility as a whole.

EUG 2

EUG 2 previously included emissions from Wall Boiler Unit 1 (B-02-1). Wall Boiler Unit 1 (B-02-1) has been permanently rendered inoperable.

EUG 3 Combustion Sources - Wall Boiler Unit 2

EU	Point	Make/National ID#	MW	MMBTU/hr	Const. Date
B-02	2	Foster-Wheeler #6905	520	5,296	03/24/1982

Stack Parameters

EU/Point	Height (Feet)	Diameter (Feet)	Flow (ACFM)	Temperature (°F)
B-02-2	505	20.0	1,522,536	160

EUG 4 Combustion Sources – Auxiliary Boilers No. 1-3

EUG 4 previously included emissions from the Fuel Gas Heaters (B-02-6 and B-02-7). Fuel Gas Heater (B-02-6) has been permanently removed from the facility and Fuel Gas Heater (B-02-7) was never installed.

EU	Point	Make/ National ID#	MW	MMBTU/hr	Const. Date
B-02	3	Zurn #18929	27	90	6/21/78
B-02	4	Zurn #18930	27	90	6/21/78
B-02	5	WTB #13053	N/A	278	2017

Stack Parameters

EU/Point	Height (Feet)	Diameter (Feet)	Flow (ACFM)	Temperature (°F)
B-02-3	261	5.0	38,812	510
B-02-4	261	5.0	38,812	510
B-02-5	261	8.0	153,013	510

EUG 5 Coal Transfer, Conveying, Crushing

EU	Pt.	Process	Const. Date
TO-03	01	Dumper vibrating feeder to CV-1 [conveyor] to yard transfer tower	3/1/78
TO-03	02	Yard transfer tower to stacker/reclaimer CV-2	3/1/78
TO-03	03	Stacker/reclaimer CV-2 to belt conveyor trailer	3/1/78
TO-03	04	Belt conveyor trailer to stacker/reclaimer boom belt	3/1/78
TO-03	05	Stacker/reclaimer boom conveyor to active storage pile	3/1/78
TO-03	06	Transfer to stacker/reclaimer as reclaim from active storage pile	3/1/78
TO-03	07	Stacker/reclaimer bucket to stacker/reclaimer boom belt	3/1/78
TO-03	08	Stacker/reclaimer boom belt to CV-2 to transfer tower	3/1/78
TO-03	09	Yard belt CV-2 transfer to crusher building CV-4	3/1/78
TO-03	10	Conveyor CV-4 transfer to crusher surge bin	3/1/78
TO-03	11	Crusher surge bin transfer to crusher	3/1/78
TO-03	12	Crusher transfer to plant transfer CV-6A or CV-6B	3/1/78
TO-03	13	From CV-6A/6B at plant transfer bldg. to tripper gallery CV-7A/7B	3/1/78
TO-03	14	CV-7A or -7B transfer to coal silos via traveling trippers	3/1/78
TO-03	15	Yard transfer tower to emergency stacker belt CV-3	3/1/78
TO-03	16	Emergency stacker telescopic chute to emergency coal pile	3/1/78
TO-03	17	Transfer from reclaim equipment in emergency stockpile to emergency reclaim grizzly	3/1/78
TO-03	18	Emergency stock pile feeder to crusher house CV-5	3/1/78
TO-03	19	OK coal pile feeder to crusher house CV-8	3/24/82
TO-03	20	CV-8 to crusher tower	3/1/78
TO-03	21	Crusher tower transfer to crusher surge bin	3/1/78
TO-03	22	Crusher surge bin transfer to crusher jaws	3/1/78
TO-03	23	Crusher transfer to plant transfer tower CV-6A or CV-6B	3/1/78

EU	Pt.	Process	Const. Date
TO-03	24	From CV-6A/6B at plant transfer tower to tripper gallery CV-7A/7B	3/1/78
TO-03	25	CV-7A or -7B to coal silo	3/1/78
TO-03	30	Mixer/crusher #1/2	2011
TO-03	31	Mixer/crusher #1/2 to CV-6A/B	2011
CU-03	01	Wyoming coal railcar unloading to hopper	3/1/78

Pollution control equipment, rotoclones, are used in coal handling. These involve a dry cyclone to remove large particles followed by a water spray to clump fine particles and a second cyclone to remove the aggregated material. All operate at ambient temperatures, have efficiencies of at least 83%, and serve multiple points.

Location	Diameter (in)	Flow (cfm)	Height above grade (ft)
Coal dumper building	36	24,000	-0-
Coal yard transfer tower	24	14,000	31
Coal crusher house (WY)	27.5	17,200	46
Coal crusher house (OK)	18	10,000	46
Plant transfer tower	36	23,450	145
Plant transfer tower	36	23,450	145
Wall Boiler Unit 2 DA room	36	23,450	116
Wall Boiler Unit 2 tripper room	36	14,000	116

EUG 6 Materials Handling

EU	Point	Process	Const. Date
BL-06	01	Bottom ash loading (hopper to truck)	3/1/78
BU-06	01	Bottom ash unloading to hopper	3/1/78
FL-05	01	Fly ash loading (hopper to truck)	3/1/78
FU-05	01	Fly ash unloading to hopper	3/1/78
LU-04	01	Truck unloading (lime) to hopper	3/1/78
PAC-01	01	Bin vent - PAC Silo 1	2016
PAC-02	02	Bin vent - PAC Silo 2	2016

Baghouses serve the lime and fly ash facilities and the Wall Boiler Unit 2 (B-02-2) economizer. The baghouses typically have large rectangular exhausts, operate at ambient temperatures, and have manufacturer's guarantees of less than 0.02 gr/acf. Baghouse information is listed in the following table.

Location	Flow (cfm)	Height above grade (ft)
Lime loading building	100,000	22
Two (2) fly ash silos	2,713 (each)	86
Two (2) fly ash silos	3,215 (each)	86
Wall Boiler Unit 2 (B-02-2) economizer	2,713	86

EUG 7 Truck & Maintenance Vehicle Traffic and Material Storage

EU	Pt.	Activity	Const. Date
CU-03	02	Truck unloading (OK coal) to yard	3/1/78
MV-03	01	Maintenance of inactive coal pile – unpaved road	3/1/78
MV-03	02	Reclaim coal from inactive storage to active storage – unpaved road	3/1/78
MV-03	03	Reclaim coal from emergency stockpile – unpaved road	3/1/78
MV-03	04	Reclaim coal from inactive coal pile to active coal pile – unpaved road	3/1/78
MV-03	05	Coal reclaim to grizzly – unpaved road	3/1/78
MV-03	06	Loaded OK coal truck delivery – unpaved road	3/24/82
MV-03	07	Empty OK coal truck delivery – unpaved road	3/24/82
MV-03	08	Maintenance and shaping of active storage pile – unpaved road	3/1/78
MV-05	01	Loaded fly ash truck traffic – ash disposal area – paved & unpaved roads	3/1/78
MV-05	02	Empty fly ash truck traffic – ash disposal area – paved & unpaved road	3/1/78
MV-05	03	Maintenance of ash disposal area – unpaved road	3/1/78
MV-06	01	Loaded bottom ash truck traffic – ash disposal area – paved & unpaved road	3/1/78
MV-06	02	Empty bottom ash truck traffic – ash disposal area – paved & unpaved road	3/1/78
VT-03	01	Loaded OK coal truck delivery – paved road	3/24/82
VT-03	02	Empty OK coal truck delivery – paved road	3/24/82
VT-04	01	Loaded lime truck delivery – paved road	3/24/82
VT-04	02	Empty lime truck delivery – paved road	3/24/82
VT-05	01	Loaded fly ash truck delivery – paved road	3/1/78
VT-05	02	Empty fly ash truck delivery – paved road	3/1/78
VT-06	01	Loaded bottom ash truck delivery – paved & unpaved roads	3/1/78
VT-06	02	Empty bottom ash truck delivery – paved & unpaved roads	3/1/78
VT-09	01	Loaded PAC truck delivery – paved road	2016
VT-09	02	Empty PAC truck delivery – paved road	2016
VT-10	01	Loaded aqueous ammonia truck delivery – paved road	2016
VT-10	02	Empty aqueous ammonia truck delivery – paved road	2016
WE-03	01	Active Wyoming coal pile – wind	3/1/78
WE-03	02	Inactive Wyoming coal pile – wind	3/1/78
WE-03	03	Active Oklahoma coal pile – wind	3/24/82
WE-03	04	Emergency coal pile – wind	3/1/78
WE-08	01	Fly ash disposal area – wind	3/1/78

EUG 8 Combined Cycle Combustion Turbine Unit 3

EU	Point	Name & Make	MMBTU/hr	Serial #	Const. Date
T-01	1	MHI 501J with Duct Burners	4,160.9	A/141100	2017

Stack Parameters

EU/Point	Height (Feet)	Diameter (Feet)	Flow (ACFM)	Temperature (°F)
T-01-1	260	23.9	5,332,455	700

EUG 9 Limited Use Engines

EU	Point	Description	Hp	Serial #	Const. Date
EG-01	1	Emergency Generator Engine	1,190	59675	8/79
EG-02	2	Emergency Generator Engine	1,190	24Z00966	9/85
FP-03	1	Fire Pump Engine	390	10789853	11/78
EG-03	3	Emergency Generator Engine	2,922	33204737	2016

Insignificant Sources

Various pieces of equipment fit the definition of an insignificant activity.

SECTION VI. EMISSIONS

EUG 2

EUG 2 previously included emissions from Wall Boiler Unit 1 (B-02-1). Wall Boiler Unit 1 (B-02-1) has been permanently rendered inoperable.

EUG 3 Combustion Sources - Wall Boiler Unit 2

Emissions from Wall Boiler Unit 2 (B-02-2)

Source EU/Point	Hourly Throughput	Pollutant	Emission Factor	Emissions (b)	
				lb/hr	TPY
Wall Boiler Unit 2 B-02-2	5,296 MMBTU or 307.05 tons (a)	PM/PM_{10}	0.028 lb/MMBTU (c)	147.49 (c)	646.01
		VOC	0.060 lb/ton (d)	18.42	80.69
		CO	0.27 lb/MMBTU (e)	1,429.92 (e)	6,263.05 (e)
		SO_2	0.6 lb/MMBTU (f)	3,177 (f)	13,915.26 (f)
		NO_X	0.5 lb/MMBTU (g)	2,648.00	11,598.24
		Fluorides	0.0019120 lb/MMBTU (h)	10.13	44.35
		Beryllium	0.0002090 lb/MMBTU (h)	0.005 (i)	0.02
		Lead	0.0000160 lb/ton (h)	0.005	0.02
		Mercury	0.04335 lb/hr (j)	0.048	0.21

(a) Determined by weighted average heating value of Wyoming and Oklahoma coal, using design criteria.
(b) Unless otherwise noted, lb/hr × 8,760 hr/yr; no limit established by original permit.
(c) Authorized in Permit No. 81-114-O.

(d) The emission factor is based on AP-42 (9/98), Section 1.1, Table 1.1-19 (PC-Fired, Dry Bottom, TNMOC).
(e) CO BACT emission limit evaluated and determined in Section VII of the Memorandum of this permit. Compliance shall be demonstrated as indicated in Specific Condition No. 23 through annual stack tests.
(f) Emission limits established in Permit PSD-OK-552 (and 81-114-O). No annual limits were established.
(g) The emission factor is based on stack testing conducted in 12/1981.
(h) Emissions were determined from an analysis performed for Wall Boiler Unit 2. This analysis can be found in the application for Permit No. 81-114-C, received on October 23, 1981. The permit, Permit No. 81-114-C, was issued on April 17, 1987.
(i) The performance test of August 12, 1986, showed emissions less than the detectable limit of 0.005 lb/hr at Wall Boiler Unit 2 following the ESP.
(j) Mercury emission testing was performed as part of EPA's Electric Utility Steam Generating Unit Information Collection Effort. Testing of Wall Boiler Unit 2 occurred at 90% of nameplate MW.

EUG 4 Combustion Sources – Auxiliary Boilers No. 1-3

EUG 4 previously included emissions from the Fuel Gas Heaters (B-02-6 and B-02-7). Fuel Gas Heater (B-02-6) has been permanently removed from the facility and Fuel Gas Heater (B-02-7) was never installed.

Emissions for Auxiliary Boiler No. 1 (B-02-3)

Source EU/Point	Rate		Pollutant	Emission Factor (lb/MMSCF)	Emissions	
	Hourly (SCF)	Annual (MMSCF)			(lb/hr)	(TPY) [(a)]
Auxiliary Boiler No. 1 B-02-3 Natural Gas	90,000	248.4	PM/PM_{10}	13.5 [(b)]	1.22	1.68
			VOC	6.2 [(b)]	0.56	0.77
			CO	38 [(b)]	3.42	4.72
			SO_2	14.3 [(c)]	1.28	1.77
			NO_X	38 [(b)]	3.42	4.72

a. Based on equivalent hours of 2,760 hours of operation per year at full load.
b. Manufacturer's data.
c. AP-42 (7/98), Section 1.4, Table 1.4-1, fuel sulfur content = 5 grains/100 SCF; 1,030 BTU/SCF.

Emissions for Auxiliary Boiler No. 2 (B-02-4)

Source EU/Point	Rate		Pollutant	Emission Factor (lb/MMSCF)	Emissions	
	Hourly (SCF)	Annual (MMSCF)			(lb/hr)	(TPY) [(a)]
Auxiliary Boiler No. 2 B-02-4 Natural Gas	90,000	248.4	PM/PM_{10}	13.5 [(b)]	1.22	1.68
			VOC	6.2 [(b)]	0.56	0.77
			CO	38 [(b)]	3.42	4.72
			SO_2	14.3 [(c)]	1.28	1.77
			NO_X	38 [(b)]	3.42	4.72

(a) Based on equivalent hours of 2,760 hours of operation per year at full load.
(b) Manufacturer's data.
(c) AP-42 (7/98), Section 1.4, Table 1.4-1, fuel sulfur content = 5 grains/100 SCF; 1,030 BTU/SCF.

Emissions for Auxiliary Boiler No. 3 (B-02-5)

Source EU/Point	Rate		Pollutant	Emission Factor (lb/MMSCF)	Emissions	
	Hourly (MSCF)	Annual (MMSCF)			(lb/hr)	(TPY) (a)
Auxiliary Boiler No. 3 B-02-5 Natural Gas	270	296.9	PM/PM_{10}	13.5 (b)	3.65	1.60
			VOC	6.2 (b)	1.67	0.73
			CO	38 (b)	10.26	4.49
			SO_2	14.3 (c)	3.85	1.69
			NO_X	38 (b)	10.26	4.49

(a) Based on equivalent hours of 876 hours of operation per year at full load.
(b) Manufacturer's data.
(c) AP-42 (7/98), Section 1.4, Table 1.4-1, fuel sulfur content = 5 grains/100 SCF; 1,030 BTU/SCF.

EUG 5 Coal Transfer, Conveying, Crushing

Emissions caused by the transfer, conveying, and crushing of coal are detailed in the following table. The emission unit/point numbers reference in the table below are the activities listed under EUG 5 in Section V of this Memorandum. The various amounts of coal handled listed in the following table are based on the conveyor handling capacity and the expected number of drop points. The emission factors utilized are based on the drop calculations from Equation 1 of AP-42 (11/06), Section 13.2.4: $E = k(0.0032)((U/5)^{1.3}/(M/2)^{1.4})$, where wind speed (U) = 10.3 mph, per meteorological data for Tulsa; material moisture contents (M) = 1.36% for Wyoming coal and 4.7% for Oklahoma coal, per the application for Permit No. 81-114-C, received on October 23, 1981; and the appropriate particle size multiplier (k): TSP = 0.74, PM_{10} = 0.35, and $PM_{2.5}$ = 0.053. TSP emissions are converted to PM_{10} or to $PM_{2.5}$ by taking the ratio of k-values. Thus, PM_{10} = 0.35/0.74 = 47.3% of TSP and $PM_{2.5}$ = 0.053/0.74 = 7.2% of TSP. The silos and day bins have bin vent dust collectors guaranteed at 0.005 gr/DSCF. All emissions from the silos and day bins are $PM_{2.5}$.

Emissions from Coal Transfer, Conveying, and Crushing

EU/Point	Emission Factor (lb/ton)	Coal Handled		Control Efficiency (%)	TSP Emissions	
		(TPH)	(TPY × 10^3)		(lb/hr)	(TPY)
TO-03-01	0.01040	3,000	5,386	90 (a)	3.12	2.80
TO-03-02	0.01040	3,000	5,386	95 (b)	1.56	1.40
TO-03-03	0.01040	1,800	4,572	30 (c)	13.10	16.64
TO-03-04	0.01040	1,800	4,572	30 (c)	13.10	16.64
TO-03-05	0.01040	1,800	4,572	80 (d)	3.74	4.75
TO-03-06	0.01040	1,800	5,238	50 (e)	9.36	13.61
TO-03-07	0.01040	1,800	5,238	30 (c)	13.10	19.06
TO-03-08	0.01040	1,800	5,238	30 (c)	13.10	19.06
TO-03-09	0.01040	1,600	5,238	90 (f)	1.66	2.72
TO-03-10	0.01040	1,600	5,238	95 (b)	0.83	1.36
TO-03-11	0.01040	1,600	5,238	95 (b)	0.83	1.36
TO-03-12	0.01040	1,600	5,238	95 (b)	0.83	1.36
TO-03-13	0.01040	1,600	5,238	95 (b)	0.83	1.36

EU/Point	Emission Factor (lb/ton)	Coal Handled		Control Efficiency (%)	TSP Emissions	
		(TPH)	(TPY × 10^3)		(lb/hr)	(TPY)
TO-03-14	0.01040	1,600	5,238	95 [(b)]	0.83	1.36
TO-03-15	0.01040	2,250	814	95 [(b)]	1.17	0.21
TO-03-16	0.01040	2,250	814	80 [(g)]	4.68	0.85
TO-03-17	0.01040	N/A	41	-0-	N/A	0.21
TO-03-18	0.01040	800	814	-0-	8.32	4.23
TO-03-19	0.00183	800	134	90 [(f)]	0.15	0.01
TO-03-20	0.00183	800	134	95 [(b)]	0.07	0.01
TO-03-21	0.00183	800	134	95 [(b)]	0.07	0.01
TO-03-22	0.00183	800	134	95 [(b)]	0.07	0.01
TO-03-23	0.00183	800	163	95 [(b)]	0.07	0.01
TO-03-24	0.00183	800	163	95 [(b)]	0.07	0.01
TO-03-25	0.00183	800	163	95 [(b)]	0.07	0.01
TO-03-30	0.0054 [(h)]	16	44	95 [(b)]	<0.01	0.01
TO-03-31	0.01040	16	44	95 [(b)]	0.01	0.01
CU-03-01	0.01040	3,000	5,386	90 [(f)]	3.12	2.80
TSP Totals					**93.88**	**111.86**
PM_{10} Totals					**44.41**	**52.91**
$PM_{2.5}$ Totals					**6.76**	**8.05**

(a) Control consists of total enclosure and wet surfactant spray.
(b) Control consists of total enclosure and capture by wet rotoclone.
(c) The coal remains wet from previous spraying.
(d) Control consists of wet spray bar on bucket wheel, containing a binding agent.
(e) Control consists of wet spray bars and periodic rain.
(f) Control consists of partial enclosure and wet surfactant spray, containing a binding agent.
(g) Control consists of a telescopic chute with a dust control binding agent.
(h) Emission factor from AP-42 (8/04), Section 11.19.2, Table 11.19.2-2 for Tertiary Crushing (SCC 3-05-030-03) and EPA FIRE database for SCC 3-05-010-10 (PM: 0.02 lb/ton; PM_{10}: 0.006 lb/ton). It covers WY and OK coals.

EUG 6 Materials Handling

Emissions caused by material handling are detailed in the following tables. The emission unit/point numbers reference in the tables below are the activities listed under EUG 6 in Section V of this Memorandum. The amounts of material handled, as listed in the following table, are based on the conveyor capacity. The emission factors utilized are based on the drop calculations from Equation 1 of AP-42 (11/06), Section 13.2.4: $E = k(0.0032)\left((U/5)^{1.3}/(M/2)^{1.4}\right)$, where wind speed (U) = 10.3 mph, per meteorological data for Tulsa; material moisture content (M) for bottom ash, fly ash, and lime is taken from the application for Permit No. 81-114-C, received on October 23, 1981; and the appropriate particle size multiplier (k): TSP = 0.74, PM_{10} = 0.35, and $PM_{2.5}$ = 0.053. TSP emissions are converted to PM_{10} or to $PM_{2.5}$ by taking the ratio of k-values. Thus, PM_{10} = 0.35/0.74 = 47.3% of TSP and $PM_{2.5}$ = 0.053/0.74 = 7.2% of TSP.

Emissions from Material Handling

EU/Point	Emission Factor (lb/ton)	Amount Handled		Control Efficiency (%)	TSP Emissions	
		(TPH)	(TPY)		lb/hr	TPY
BL-06-01	0.00064	47	27,120	100 (a)	-0-	-0-
BU-06-01	0.00064	3,502	27,120	100 (a)	-0-	-0-
FL-05-01	0.00343	3,510	373,480	99 (b)	0.12	0.01
FU-05-01	0.00343	3,510	373,480	25 (c)	9.03	0.48
LU-04-01	0.00168	15	27,100	99 (b)	<0.01	<0.01
TSP Totals					**9.15**	**0.49**
PM_{10} Totals (d)					**4.33**	**0.23**
$PM_{2.5}$ Totals (d)					**0.66**	**0.04**

(a) This is wet ash, with no measurable emissions.
(b) Control consists of total enclosure and evacuation to a baghouse.
(c) Partial control is attributable to periodic rain.
(d) PM_{10} = 47.3% of all PM and that $PM_{2.5}$ = 7.2% of all PM.

The emissions from the PAC Silos 1 and 2 bin vents are based on the bin vent flow rate, emission factors from manufacturer's data, and assuming continuous operation.

Emissions from the Bin Vent – PAC Silos 1 and 2

EU/Point	Emission Factor (gr/dscf)	Flow Rate (dscfm)	Control Efficiency (%)	TSP Emissions	
				(lb/hr)	(TPY)
PAC-01-01	0.005	1,078	N/A	0.05	0.20
PAC-01-02	0.005	1,078	N/A	0.05	0.20
$PM_{10}/PM_{2.5}$ Totals				**0.10**	**0.40**

EUG 7 Truck & Maintenance Vehicle Traffic and Material Storage

Emissions caused by truck and maintenance vehicle traffic and materials storage are detailed in the following tables. The emission unit/point numbers reference in the tables below are the activities listed under EUG 7 in Section V of this Memorandum.

Emissions from truck and maintenance vehicle traffic on unpaved roads are detailed in the following table. Emission factors for unpaved areas are calculated from Equation 1a of AP-42 (11/06), Section 13.2.2: $E\ (lb/VMT) = k\ (s/12)^a\ (W/3)^b$. VMT stands for vehicle miles traveled, k is a particle size multiplier, s is the silt content of the road surface, and W is the average vehicle weight. Values for k, a, and b were taken from AP-42 (11/06), Section 13.2.2, Table 13.2.2-2 for Industrial Roads. The particle size multiplier, k, is equal to 1.5 for PM_{10} and 0.15 for $PM_{2.5}$.The average silt content is 30 % in the ash area and 2.4% in the coal area.

Emissions from Unpaved Road Vehicle Traffic

EU/Point	s (%)	W (tons)	E (lb/VMT)	2008 VMT	Control Efficiency (%)	PM_{10} Emissions (TPY)
CU-03-02	2.4	37	1.09	1,176	80 [(a)]	0.13
MV-03-01	2.4	50	1.25	4,380	80 [(a)]	0.55
MV-03-02	2.4	50	1.25	10,950	80 [(a)]	1.37
MV-03-03	2.4	10	0.61	4,992	80 [(a)]	0.30
MV-03-04	2.4	50	1.25	10,950	80 [(a)]	1.37
MV-03-05	2.4	10	0.61	2,190	80 [(a)]	0.13
MV-03-06	2.4	37	1.09	126	80 [(a)]	0.01
MV-03-07	2.4	12	0.66	126	80 [(a)]	0.01
MV-03-08	2.4	50	1.25	4,000	80 [(a)]	0.50
MV-05-01	30	54.6	12.6	1,132	90 [(b)]	0.71
MV-05-02	30	38.6	10.8	1,132	90 [(b)]	0.61
MV-05-03	30	52	12.4	4,000	90 [(b)]	2.47
MV-06-01	30	27	9.20	363	90 [(b)]	0.17
MV-06-02	30	11	6.14	363	90 [(b)]	0.11
VT-06-01	30	40	11.0	409	90 [(b)]	0.22
VT-06-02	30	15	7.06	409	90 [(b)]	0.14
PM_{10} Total						**8.81**
$PM_{2.5}$ Total						**0.88** [(c)]

(a) Dust control provided by a binding agent.
(b) Dust control provided by a chemical solution in water.
(c) $PM_{2.5}$ emissions are proportioned from the PM_{10} value based on the respective values of k.

Emissions from truck and maintenance vehicle traffic on paved roads are detailed in the following table. Emission factors for paved areas are calculated from Equation 2 of AP-42 (1/11), Section 13.2.1: $E\ (lb/VMT) = [k\ (sL)^{0.91} \times (W)^{1.02}]\ (1 - (P/4N))$. VMT stands for vehicle miles traveled, k is a particle size multiplier, sL is the road surface silt loading, W is the average vehicle weight, and P is the number of days with rain in excess of 0.01 inches. Values for k were taken from AP-42 (1/11), Section 13.2.1, Table 13.2.1-1, where k equals 0.0022 lb/VMT for PM_{10} and 0.00054 lb/VMT for $PM_{2.5}$. The road surface silt loading values were taken from AP-42 (1/11), Section 13.2.1, Tables 13.2.1-2 & 3. P is assumed to be 95, and N is 365 days per year. The control efficiency for periodic sweeping was considered to be 75%.

Emissions from Paved Road Vehicle Traffic

EU/Point	sL [(a)] (g/m^2)	W (tons)	E (lb/VMT)	2008 [(b)] (VMT)	Control Efficiency (%)	PM_{10} Emissions (TPY)
MV-05-01	9.7	54.6	0.962	377	75	0.05
MV-05-02	9.7	38.6	0.675	377	75	0.03
MV-06-01	9.7	27.0	0.469	598	75	0.04
MV-06-02	9.7	11.0	0.188	598	75	0.01
VT-03-01	9.7	36.75	0.642	462	75	0.04
VT-03-02	9.7	11.75	0.201	462	75	0.01

EU/Point	sL [a] (g/m^2)	W (tons)	E (lb/VMT)	2008 [b] (VMT)	Control Efficiency (%)	PM_{10} Emissions (TPY)
VT-04-01	9.7	37.5	0.656	289	75	0.02
VT-04-02	9.7	12.5	0.214	289	75	0.01
VT-05-01	9.7	40.0	0.700	4,150	75	0.36
VT-05-02	9.7	15.0	0.258	4,150	75	0.13
VT-06-01	9.7	40.0	0.700	1,125	75	0.10
VT-06-02	9.7	15.0	0.258	1,125	75	0.04
VT-09-01	0.6	36.75	0.415	35 [c]	75	<0.001
VT-09-02	0.6	11.75	0.130	35 [c]	75	<0.001
VT-10-01	0.6	36.75	0.415	99 [c]	75	<0.001
VT-10-02	0.6	11.75	0.130	99 [c]	75	<0.001
PM_{10} Total						**0.84**
$PM_{2.5}$ Total						**0.21 [d]**

(a) AP-42 (1/11), Section 13.2.1, Table 13.2.1-3 mean silt-loading value for Iron & Steel Production. AP-42 (1/11), Section 13.2.1, Table 13.2.1-2, ubiquitous baseline for ADT < 500.
(b) Except as otherwise noted.
(c) Estimated in the permit application for Permit No. 2009-179-C (M-3).
(d) $PM_{2.5}$ emissions are proportioned from the PM_{10} value based on the respective values of k.

Emissions from wind erosion of material storage piles are detailed in the following table. The emission factors utilized are based on the drop calculations from Equation 1 of AP-42 (11/06), Section 13.2.4: $E = k(0.0032)\ ((U/5)^{1.3}/(M/2)^{1.4})$, where wind speed (U) = 10.3 mph, per meteorological data for Tulsa; material moisture contents (M) = 1.36% for Wyoming coal and 1.36% for Oklahoma coal, per the application for Permit No. 81-114-C, received on October 23, 1981; and the appropriate particle size multiplier (k): PM_{10} = 0.35. An 80% control efficiency is used to account for the application of a dust control binding agent sprayed onto the coal, an additional 5% control efficiency is used for long term storage to account for chemically stabilizing portions of the inactive coal piles, and a 50% control efficiency is used to the fly ash disposal area to account for watering by truck. The calculations do not take into account reductions due to precipitation.

Emissions from Material Storage

EU/Point	Storage Pile Area	Number of Days	Control Efficiency	PM_{10} Emissions
	(acres)	(days)	(%)	(TPY)
WE-03-01	2.34	365	80	0.52
WE-03-02	33.3	365	85	4.83
WE-03-03	4.4	365	80	0.86
WE-03-04	1.6	365	85	0.32
WE-08-01	16.6	365	50	8.60
PM_{10} Total				**15.13**

Emissions Summary from EUG 7 –
Truck & Maintenance Vehicle Traffic and Material Storage

Source	PM_{10} Emissions (TPY)	$PM_{2.5}$ Emissions (TPY)
Unpaved Road Vehicle Traffic	8.81	0.88
Paved Road Vehicle Traffic	0.84	0.21
Material Storage	15.13	-
Totals	**24.78**	**1.09**

EUG 8 Combined Cycle Combustion Turbine Unit 3

Emissions for the combined cycle combustion Turbine Unit 3 (T-01-1) are based on emission factors from vendor's data, a heat input of 4,160.9 MMBTUH, and continuous operation.

Emissions from Turbine Unit 3 (T-01-1)

Pollutant	Emission Factor (lb/MMBTU)	Emissions	
		(lb/hr)	(TPY)
$PM/PM_{10}/PM_{2.5}$	0.014	58.25	255.15
VOC	0.004	16.64	72.90
CO	0.032	133.15	583.19
SO_2	0.015	62.41	273.37
NO_X	0.060	249.65	1,093.48
H_2SO_4	0.005	20.80	91.12
Lead	---	---	---

EUG 9 Limited Use Engines

Emission factors for the emergency generator diesel-fired engines (EG-01-01 and EG-02-02) are based on AP-42 (10/96), Section 3.4, Table 3.4-1 and the rating of 1,190-Hp for each engine. SO_2 emissions assume a fuel sulfur content of 0.0015% by weight and complete conversion of sulfur to SO_2. Annual emissions assume 500 hours of operation per year.

Emissions from Emergency Generator Engines (EG-01-1 & EG-02-2)

Pollutant	Emission Factor (lb/hp-hr)	EG-01-1 Emissions		EG-01-2 Emissions	
		(lb/hr)	(TPY)	(lb/hr)	(TPY)
$PM/PM_{10}/PM_{2.5}$	7.00 E-4	0.83	0.21	0.83	0.21
VOC	7.05 E-4	0.84	0.21	0.84	0.21
CO	5.50 E-3	6.55	1.64	6.55	1.64
SO_2	1.21 E-5	0.01	<0.01	0.01	<0.01
NO_X	0.024	28.56	7.14	28.56	7.14
H_2SO_4	0.0071	<0.01	<0.01	<0.01	<0.01

Emission factors for the emergency fire pump diesel-fired engine (FP-03-01) are based on AP-42 (10/96), Section 3.3, Table 3.3-1, except for SO_2, and the engine rating of 390-Hp. SO_2 emissions are based on AP-42 (10/96), Section 3.4, Table 3.4-1, assume a fuel sulfur content of 0.0015% by weight, and complete conversion of sulfur to SO_2. Annual emissions assume 500 hours of operation per year.

Emissions from Fire Pump Engine (FP-03-1)

Pollutant	Emission Factor (lb/hp-hr)	Emissions	
		(lb/hr)	(TPY)
$PM/PM_{10}/PM_{2.5}$	2.20 E-3	0.86	0.22
VOC	2.51 E-3	0.98	0.25
CO	6.68 E-3	2.61	0.65
SO_2	1.21 E-5	<0.01	<0.01
NO_X	0.031	12.09	3.02
H_2SO_4	0.0071	<0.01	<0.01

Emission factors for the emergency generator engine (EG-03-3) are from manufacturer's data and the engine rating of 2,922-Hp. SO_2 numbers assume 0.0015%$_W$ and complete conversion of sulfur. Note that all factors are below the NSPS, Subpart IIII requirements for each pollutant. Annual emissions assume 100 hours of operation per year.

Emissions from Emergency Generator Engine (EG-03-3)

Pollutant	Emission Factor (g/hp-hr)	NSPS Limits (g/hp-hr)	Emissions	
			(lb/hr)	(TPY)
$PM/PM_{10}/PM_{2.5}$	0.10	0.15	0.64	0.03
VOC	0.085	N/A	0.55	0.03
CO	0.75	2.60	4.83	0.24
SO_2	0.0046	N/A	0.03	<0.01
NO_X	4.11	4.80	26.48	1.32
H_2SO_4	0.0071	N/A	0.05	<0.01

Emissions Summary from EUG 9 - Limited Use Engines

Pollutant	Total Emissions	
	(lb/hr)	(TPY)
$PM/PM_{10}/PM_{2.5}$	3.17	0.66
VOC	3.20	0.69
CO	20.53	4.17
SO_2	0.06	<0.01
NO_X	95.69	18.63
H_2SO_4	0.05	<0.01

Insignificant Activities Cooling Towers

Although emissions from cooling towers are considered trivial, the applicant has calculated particulate emissions, using the standard equation:

$$E = gpm \times DR \times 8.34\ lb/gal \times TDS \times 8{,}760\ hr/yr \times 60\ min/hr \times ton/2{,}000\ lbs,$$

Where the drift rate (DR) is 0.0005%, total dissolved solids (TDS) is 1,575 ppm$_W$, and the circulation rates for the tower and the chiller are 129,000 gpm and 18,000 gpm, respectively. In this instance, $PM_{2.5}$ is taken to be 0.6 × PM_{10}, per a factor from South Coast Air Quality Management District. Emissions are shown in the following table.

Emissions from the Cooling Towers & Chillers

	PM (TPY)	PM_{10} (TPY)	$PM_{2.5}$ (TPY)
Cooling Tower	2.23	2.23	1.34
Chiller	0.31	0.31	0.19

Estimated Facility-Wide Criteria Pollutant Emissions

EUG	PM_{10}		VOC		CO		SO_2		NOx	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
EUG 3	147.49	646.01	18.42	80.69	1,429.92	6,263.05	3,177.00	13,915.26	2,648.00	11,598.24
EUG 4	6.08	4.95	2.79	2.27	17.10	13.93	6.42	5.23	17.10	13.93
EUG 5	44.41	52.91	----	----	----	----	----	----	----	----
EUG 6	4.42	0.64	----	----	----	----	----	----	----	----
EUG 7	----	24.48	----	----	----	----	----	----	----	----
EUG 8	58.25	255.15	16.64	72.90	133.15	583.19	62.41	273.37	249.65	1,093.48
EUG 9	3.17	0.66	3.20	0.69	20.53	4.17	0.06	<0.01	95.69	18.63
CT	----	2.54	----	----	----	----	----	----	----	----
Total	**263.81**	**987.33**	**41.06**	**156.56**	**1,600.70**	**6,864.34**	**3,245.90**	**14,193.87**	**3,010.44**	**12,724.28**
Previously Permitted Emissions[(a)]	377.25	1,153.20	62.70	188.61	1,287.90	4,865.00	3,320.80	14,304.80	4,091.40	14,319.90
Net Changes	(-113.44)	(-165.87)	(-21.64)	(-32.05)	(+312.80)	(+1,999.34)	(-74.90)	(-110.93)	(-1,080.96)	(-1,595.63)

(a) Emissions are from the most recently issued permit; Permit No. 2014-1728-TVR3 (M-3).

Speciated and Trace Compounds from Coal Combustion Emissions

Numerous volatile and metallic compounds and elements were addressed in the operating permit. Because there is no expected increase in fuel use and because these numbers are generally small, there is no need to repeat the earlier analysis here. Lead and fluorides, each with estimated emissions of some interest in the operating permit, are considered in this memorandum in the discussion that covers criteria pollutants.

SECTION VII. PSD REVIEW

The Grand River Energy Center is an existing PSD major source for CO emissions. GRDA requested to revise the CO emission factor for Wall Boiler Unit 2 (B-02-2) from 0.17 lb/MMBtu to 0.27 lb/MMBtu. The revision of the CO emission factor for Wall Boiler Unit 2 (B-02-2) will result in exceeding the 0.17 lb/MMBtu (30-day rolling average) emission limit established in Permit No. 2009-179-C (M-2) PSD. This emission limit was also utilized in the following active major source construction permits: Permit No. 2009-179-C (M-3), 2009-179-C (M-4), and 2009-179-C (M-5). The original CO emission limit for Wall Boiler Unit 2 (B-02-2) was based on a one-time steady state performance test and no safety factor was added. Since the current permit limit for CO is based on a BACT limit (lb/MMBtu), GRDA was required to address the applicable aspects of PSD review for Wall Boiler Unit 2 (B-02-2).

GRDA used the "actual-to-potential applicability test for projects that only involve existing emissions units" as outlined in OAC 252:100-8-30(b)(6) to evaluate if a significant increase will occur. Since the change only affects the CO emissions from Wall Boiler Unit 2 and the PSD review for CO emissions from Permit No. 2009-179-C (M-2) PSD, only CO emissions are addressed.

The baseline actual emissions (BAE) for CO were calculated using the actual annual heat input and the actual annual hours of operation for the given baseline period. The baseline period used in Permit No. 2009-179-C (M-2) PSD was the 5-year period from 2007-2012. The baseline period used for CO was the consecutive 24-months of January 2008 to January 2009. The sum of hourly Continuous Emissions Monitoring (CEM) data for each year was used to evaluate the BAE for Wall Boiler Unit 2 (B-02-2).

Wall Boiler Unit 2 (B-02-2) Baseline Actual Emissions

	CO
	TPY
2008	1,726.57
2009	982.09
BAE	2,708.66

The potential-to-emit (PTE) for CO was calculated using a maximum capacity of 5,296-MMBtu/hr, continuous operation. The proposed 0.27 lb/MMBtu CO emission factor was used to evaluate the PTE for Wall Boiler Unit 2 (B-02-2).

Wall Boiler Unit 2 (B-02-2) Potential Emissions

	CO
	TPY
PTE [(a)]	6,263.05

There are no other emission increases at the facility that are directly related to the proposed project. The total project emissions increases were calculated by subtracting the BAE from the PTE for Wall Boiler Unit 2. The total project emissions increases were then compared with the PSD significant emission rates (SERs) to determine PSD applicability.

Wall Boiler Unit 2 (B-02-2)
Project Emissions Increases and Determination of PSD Review

	CO
	TPY
PTE	6,263.05
BAE	2,708.66
Emissions Increases	3,554.39
SER	100
PSD Review Required?	**Yes**

As shown, the proposed project will increase emissions above the PSD significance level for CO, which is subject to further review. Full PSD review of emissions consists of the following. Although much of the PSD review is taken from the application verbatim, modifications have been made at various points. The review generally includes the following steps and the discussion will address each in order.

A. determination of best available control technology (BACT)
B. evaluation of existing air quality and determination of monitoring requirements
C. evaluation of PSD increment consumption
D. analysis of compliance with National Ambient Air Quality Standards (NAAQS)
E. ambient air monitoring
F. evaluation of source-related impacts on growth, soils, vegetation, visibility
G. evaluation of Class I area impact

A. BACT

As required under NSR/PSD regulations, the BACT analysis employed the USEPA's recommended top-down, five-step analysis process to determine the appropriate BACT emission limitations for the Project. The BACT analysis was conducted in the following manner.

<u>Step 1: Identify All Available Control Technologies</u>

The first step in a "top-down" analysis is to identify all available control options for the emission unit in question. These options consist of those air pollution control technologies or techniques with a practical potential for application to the emission unit and the regulated pollutant under evaluation. These potentially include lower emitting processes, practices, and post-combustion controls. Lower emitting practices can include fuel cleaning, treatment, or innovative fuel combustion techniques that are classified as pre-combustion controls. The category of post-combustion controls includes various add-on controls for the pollutant being controlled.

Oxidation Catalysts

The CO oxidation catalyst process utilizes a platinum/vanadium catalyst that oxidizes CO to CO_2. The chemical process is a straight catalytic oxidation/reduction reaction requiring no reagent. Catalytic oxidation emission reduction methods have been proven in the industry for use on natural gas and oil fueled combustion turbine sources, but not on coal fired boilers.

Good Combustion Controls

As products of incomplete combustion, CO emissions are very effectively controlled by ensuring the complete and efficient combustion of the fuel in the boilers.

<u>Step 2: Eliminate Technically Infeasible Options</u>

The second step is to eliminate the technically infeasible control options from those identified in Step 1. A technically infeasible control option is one that has not been "demonstrated"; or more specifically, a technology that has not been installed and operated successfully on a similar type of unit of comparable size. A technology is considered "demonstrated" for a given unit based on its "availability" and "applicability." "Availability" is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. “Applicability” is defined as an available control option that can reasonably be installed and operated on the unit type under consideration.

Oxidation Catalysts
The application of an oxidation catalyst to a coal fired boiler presents many substantial challenges that render this control technology not technically feasible for further consideration as a control alternative for CO. A review of the USEPA RACT/BACT/LAER Clearinghouse (RBLC) reveals that the database contains no record of add-on control equipment for the control of CO on a solid fuel boiler, and GRDA is not aware of this control technology ever having been applied to a solid fuel boiler. Technical challenges that render an oxidation catalyst control technically infeasible for Wall Boiler Unit 2 include the following.

- When installing an oxidation catalyst on a coal fired boiler the catalyst needs to be located in a flue gas high temperature region, which would most likely be prior to the economizer. This location, along with the potential fouling effects of the flue gas, would render the catalyst ineffective, even on a short-term basis.
- The oxidation catalyst will not only oxidize CO, but will also oxidize a predominant portion of SO_2 to SO_3, forming corrosive and undesirable sulfuric acid vapor emissions in the presence of water.
- Acid gases and trace metals in the flue gas from the combustion of solid fuel will quickly poison the catalyst, making the control technology ineffective in its intended role.

Good Combustion Controls
The typical measures taken to minimize the formation of NO_X during combustion (such as the installation of low-NO_X burners and overfire air (LNB/OFA)) tend to inhibit complete combustion, which increases the emissions of CO. On the other hand, high combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions, but tend to increase NO_X formation. Therefore, in terms of combustion controls, the best control technology for CO directly conflicts with the LNB/OFA’s ability to reduce NO_X. Nonetheless, LNB burner manufacturers strive for the delicate balance of decreasing NO_X emissions while at the same time limiting CO formation, resulting in good combustion control practices based on a boiler-specific and fuel-specific LNB/OFA burner design.

While the CO oxidation catalyst is eliminated from further consideration for the reasons stated above, good combustion controls are well demonstrated and available, and thus considered technically feasible for the control of CO in this BACT analysis.

<u>Step 3: Rank Remaining Control Technologies by Effectiveness</u>
The third step is to rank all the remaining control alternatives not eliminated in Step 2 based on their control effectiveness for the pollutant under review. In this step, the feasible technologies are reviewed in order to determine the control effectiveness on either a percent removal basis or emission level, or both, based on an engineering analysis and document review of the technology applied to similar units. The following informational databases, clearinghouses, documents, and studies were used to identify recent control technology determinations for similar source categories and emission units.

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC).
- USEPA's National Coal Fired Utility Projects Spreadsheet (August 2009).
- Federal/State/Local new source review permits, permit applications, and associated inspection/test reports.
- Technical journals, newsletters, and reports.
- Information from air quality control (AQC) technology suppliers.
- AQC engineering design studies for this and similar units.

A search of the information contained in the USEPA RACT/BACT/LAER Clearinghouse (RBLC) was conducted to determine the top level of CO control for new and LNB/OFA retrofit coal boilers. A search was also conducted for recently permitted new and LNB/OFA retrofit coal fired facilities whose BACT determinations have not yet been included in the current database. The results are documented in the application associated with this permit (Permit No. 2014-1728-C (M-4) PSD). The list contains 51 items and is not reproduced here. It indicates that good combustion controls (GCC) is the top control for CO emissions from coal fired boilers. In fact, GCC is the only control identified for similar sources to reduce CO emissions.

The data exhibits a very large range of CO BACT emission limit determinations by various permitting authorities across the country for new coal-fired boilers and LNB/OFA retrofits, with determinations ranging from 0.015 lb/MMBtu for newly proposed coal fired boilers to as high as 1.26 lb/MMBtu for an OFA retrofit. The more than an order of magnitude range in CO BACT determinations is reflective of the high variability of this pollutant's formation and indicative of the boiler-specific design and fuel conditions that must be taken into consideration when determining a CO BACT emission limit. Using only those retrofit boilers for which the limit is set on a 30-day average, the accepted standards average 0.268 lb/MMBTU. Forming the same average for new boilers that have 30-day averaging, yields 0.144 lb/MMBTU.

As previously mentioned, the lowest CO BACT emission limit determinations are for newly proposed boilers, while the higher CO BACT emission limit determinations are generally associated with LNB/OFA retrofit projects such as that proposed for the facility. The reason for this variability is that LNB/OFA retrofits are installed on existing coal fired boilers for the sole purpose of reducing NO_X emissions; and as such, cannot be optimized as effectively for CO reduction as they can for a new unit because of the fixed design characteristics of the existing boiler. CO emissions, as a product of incomplete combustion, are by their nature a function of the specific boiler type and the fuel characteristics, which is reflected in the emissions guarantees that vendors are willing to make for a LNB/OFA retrofit project.

Therefore, when determining CO BACT emission limits for Unit 2, it is appropriate to focus the review and analysis of previous determinations on those existing units that have recently undergone similar LNB/OFA retrofit installations and permit actions. The following 11 determinations were extracted from the previously mentioned list to illustrate determinations recently made by permitting authorities for retrofit projects similar to that proposed for GRDA's Unit 2.

CO Requirement lb/MMBTU	Averaging Period	Company	Facility/Unit Name	State	Date
0.150	30-day rolling	Minnesota Power Division of Allete, Inc.	Boswell Energy Center, Unit 4	MN	04/10
0.150	30-day	Entergy Arkansas, Inc.	Independence Plant	AR	01/17
0.163	30-day	Iowa Power and Light	Ottumwa Generating Station, Boiler 1	IA	02/07
0.200	30-day rolling	PacifiCorp	Dave Johnson, Unit 4	WY	06/08
0.250	30-day rolling	PacifiCorp	Naughton Plant, Units 1 and 2	WY	05/09
0.250	30-day rolling	PacifiCorp	Wyodak Plant, Unit 1	WY	05/09
0.250	30-day rolling	PacifiCorp	Dave Johnson, Unit 3	WY	06/08
0.350	30-day	City Utilities of Springfield	James River Power Station, Units 3, 4, and 5	MI	12/06
0.500	30-day rolling	Omaha Public Power District	Nebraska City Station, Unit 1	NE	02/09
0.500	30-day	Nebraska Public Power District	Gerald Gentleman Station, Unit 1	NE	08/09
0.600	30-day	Southwestern Electric Power Company	Flint Creek Power Plant	AR	02/18

These determinations, spanning the last 10-plus years, range from 0.2 to 1.26 lb/MMBTU, with an average CO BACT emission rate of approximately 0.33 lb/MMBTU. All but five of the CO BACT determinations specified above require a 30-day rolling average as a basis for compliance. The top, and only control technology determinations listed, is the use of GCC for the reduction of CO emissions from coal fired boilers.

Step 4: Evaluate the Most Effective Controls and Document the Results

Additional evaluations are performed to consider and compare the energy, environmental, and economic impacts associated with implementing the viable control alternatives.

The energy impact evaluation considers the energy penalty or benefit resulting from the operation of the control technology at the facility. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which ultimately affects the cost-effectiveness of the control technology.

There are no significant energy impacts that would preclude the use of GCC to limit the emissions of CO.

The environmental impact evaluation considers the collateral environmental effects resulting from the operation of each viable control alternative. Example environmental impacts may include additional water discharge and consumption, collateral emission increases, as well as disposable solids and waste generation.

As previously discussed, the typical good combustion measures taken to minimize the formation of CO, namely higher combustion temperatures, additional excess air, and optimum air/fuel mixing during combustion, are often counterproductive to the control of NO_X emissions. A proper balance of this phenomenon is a necessary task in obtaining and complying with the manufacturer's guarantees, since overly aggressive CO limits can jeopardize NO_X emissions design considerations.

The third and final impact analysis addresses the economics of the proposed control technologies in order to evaluate and compare two or more alternatives. This analysis is performed to assess the cost to purchase and operate the control technology. The capital and operating/annual cost is estimated based on the established design parameters. Information for the design parameters is obtained from established reference sources. Documented assumptions can be made in the absence of available information for the design parameters. The estimated cost of control is represented as an annualized cost ($/year) and, with the estimated quantity of pollutant removed (tons/year), the cost-effectiveness ($/tons) of the control technology is determined. Cost-effectiveness is used to assess the economic cost to achieve the required emissions reduction in the most economical manner. Two types of cost-effectiveness are considered in a BACT analysis; average and incremental cost-effectiveness. Average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option, in units of dollars/incremental ton removed. The incremental cost-effectiveness is a useful measure of economic viability when comparing technologies that have similar removal efficiencies.

Since there is only one feasible control technology to limit the emissions of CO from Wall Boiler Unit 2, a comparative cost analysis is not applicable.

<u>Step 5: Select BACT</u>
The highest ranked control technology from Step 3 that is not eliminated in Step 4 based on unacceptable economic, energy, or environmental impacts, is proposed as BACT for the pollutant and emission unit under review. Alternatively, upon proper documentation that the top level of control is not feasible for a specific unit and pollutant based on a site- and/or project-specific consideration of the aforementioned screening criteria (e.g., technical, energy, environmental, and economic considerations), then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration. BACT cannot be determined to be less stringent than the emissions limits established by an applicable NSPS for the affected air emission source. The only NSPS Subparts that apply are D and Da, neither of which establishes emission limits for CO.

Based on the preceding BACT analysis, GRDA proposes the only feasible control; GCC, for the control of CO emissions resulting from the LNB/OFA Project for Wall Boiler Unit 2. The proposed BACT for CO on Wall Boiler Unit 2 is good combustion controls to achieve an emission limit of 0.27 lb/MMBtu, based on a 30-day rolling average. The proposed BACT is consistent with findings from USEPA RBLC Clearinghouse database for similar conditions and operations.

DEQ agrees that good combustion is accepted as BACT for CO emissions from Wall Boiler Unit 2 at 0.27 lb/MMBtu (30-day rolling average).

B. Evaluation of existing air quality and determination of monitoring requirements

The AERSCREEN modeling was previously conducted using a CO emission factor of 0.30 lb/MMBTU as part of the issuance of Permit No. 2009-179-C (M-2) PSD. The proposed emission limit of 0.27 lb/MMBTU is less than this emission rate. The modeling previously conducted includes Wall Boiler Unit 1. However, as part of this project Wall Boiler Unit 1 has been removed. The ambient impact levels are only expected to decrease as a result of the removal. Therefore, revised modeling is not required. The following modeling information is from Permit No. 2009-179-C (M-2) PSD.

<u>Model Selection and Description</u>

Consistent with the available modeling applications provided for by Appendix W to Part 51 Guideline on Air Quality Models, the AERSCREEN (Version 11126) air dispersion model is used to predict maximum ground-level concentrations associated with the proposed Project's emissions. On April 11, 2011, the USEPA issued a clarification memo stating that AERSCREEN was intended to replace the SCREEN3 model as the recommended screening model. AERSCREEN is a screening version of the AERMOD model, the preferred short-range air dispersion model. AERSCREEN is a single source Gaussian plume model that provides worst-case 1-hour concentrations for a variety of source types. The AERSCREEN model also includes conversion factors to estimate worst-case 3-hour, 8-hour, 24-hour, and annual concentrations.

The AERSCREEN model is used to determine the maximum predicted ground-level concentration for CO for each applicable averaging period resulting from the emissions of the proposed Project.

<u>Source Input Parameters</u>

A series of stack tests for both Units 1 and 2 were performed at CFC in November, 2001. The averages of the stack gas volumetric flow and temperature results from these tests are used in the modeling analyses. The GEP stack heights for both Units 1 and 2 are 505 ft as discussed below. The modeled CO emission rate is conservatively based on a 0.30 lb/MMBtu emission rate and each unit's heat input of 5,131 MMBtu/hr and 5,296 MMBtu/hr for Units 1 and 2, respectively. This modeled emission rate is conservatively high and protective of the air quality standards, because the BACT emission limit for Units 1 and 2 is 0.17 lb/MMBtu.

Stack parameters and pollutant emission rates used in the modeling analysis.

Source	UTM Easting [1] (m)	UTM Northing [1] (m)	Base Elevation [2] (ft)	GEP Stack Height [3] (ft)	Stack Diameter (ft)	Exhaust Flow Rate [4] (acfm)	Exit Velocity[5] (ft/s)	Exit Temp. [4] (°F)	CO Emission Rate [6] (lb/hr)
Unit 1	294,133.01	4,007,350.57	622	505	20	1,839,483	98	301	1,539.3
Unit 2	294,203.19	4,007,270.52	622	505	20	1,895,063	101	194	1,588.8

1. Universal Transverse Mercator (UTM), Zone 15. NAD83 datum.
2. Base elevation is elevation above mean sea level (amsl).
3. GEP stack heights for both Units 1 and 2 are 505 ft based on the USEPA equation.
4. The exhaust flow rate and temperature values were obtained from averaging the results of the tests that were performed at the CFC in November, 2001.
5. The exit velocity was calculated using the exhaust flow rate and stack diameter values.
6. Emissions from these units are based on a 0.30 lb/MMBtu emission rate and Unit's 1 and 2's heat input rate of 5,131 MMBtu/hr and 5,296 MMBtu/hr, respectively.

Good engineering Practice and Building Downwash Evaluation

The dispersion of a plume can be affected by nearby structures when the stack is short enough to allow the plume to be significantly influenced by surrounding building turbulence. This phenomenon, known as structure-induced downwash, generally results in higher model-predicted ground-level concentrations in the vicinity of the influencing structure. Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in OAC 252:100-8-1.5. GEP stack height is defined as the greater of 65 meters or a height established by applying the formula Hg = H + 1.5L, where

Hg = GEP stack height,
H = height of nearby structures, and
L = lesser dimension (height or projected width) of nearby structures,

or by a height demonstrated by a fluid model or a field study that ensures that emissions from a stack do not result in excessive concentrations of any pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features. Because a fluid model analysis or a field study was not completed, the GEP stack height is defined by definition 1 or 2. The term "nearby" is further defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. The stacks for both Units 1 and 2 are built to a height of 505 feet above grade. The facility's calculated GEP stack height based on the equation referenced in OAC 252:100-8-1.5 is 505 feet above grade. Since Units 1 and 2's stack heights are set to GEP, the effects of building downwash will not be included.

Meteorology and Surface Characteristics

The AERSCREEN model incorporates the stand-alone MAKEMET program to generate the matrix of meteorological conditions. The matrix of meteorological conditions is based on site-specific surface characteristics, ambient temperatures, minimum wind speed, and anemometer height. The site-specific surface characteristics are based on output from the pre-processer AERSURFACE program, which utilizes the 1992 USGS National Land Cover Dataset to determine the site-specific surface characteristics. Minimum and maximum temperatures of -25 °F and 114 °F are based on the climatological summary from the Pryor Mesonet station. EPA default values of 0.5 m/s and 10 m are used for minimum wind speed and anemometer height, respectively. Further details about AERSURFACE follow.

USEPA guidance supports the use of AERSURFACE to process land cover data to determine the surface characteristics (i.e., surface roughness, Bowen ratio, and albedo) for the meteorological measurement site that is used to represent meteorological site conditions. Chapter 2.3.4 of ODEQ's *Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits* also indicates that surface characteristics using AERSURFACE can be used for air permit applications. The current version of AERSURFACE (Version 08009) supports the use of land cover data from the USGS National Land Cover Data 1992 archives (NLCD92). This analysis obtains digitized NLCD92 data from the USGS National Map Seamless Server. The GeoTIFF file for Oklahoma containing the land cover data is used as input for AERSURFACE. ODEQ's modeling guidance document also recommends the following input conditions for running AERSURFACE:

- Center the land cover analysis on the meteorological measurement site (the Pryor Oklahoma Mesonet Site).

- Analyze surface roughness within 1 km of measurement site.
- Utilize one sector determining the surface roughness length.
- Temporal resolution of the surface characteristics should be determined on a monthly basis.
- The region does not experience continuous snow cover for most of the winter.
- The Mesonet site is not considered an airport.
- The region is not considered an arid region.
- Utilize the default season assignment (winter=Dec, Jan, Feb; Spring=Mar, Apr, May; Summer=Jun, Jul, Aug; Fall=Sep, Oct, Nov)

Because actual observed meteorological data is not used in the screening modeling analysis (i.e., MAKEMET is utilized to create the worst-case meteorological conditions), surface moisture conditions for the Bowen Ratio cannot be assigned to specific years. Therefore, AERSURFACE is run for each of the three surface moisture conditions (i.e., average, dry and wet) to identify surface characteristics associated with the maximum predicted impacts. The following surface characteristic values are used as input to run USEPA's AERSCREEN model.

Month	Surface Roughness Length (m)	Albedo	Bowen Ratio		
			Average	Dry	Wet
Jan	0.021	0.18	0.70	1.92	0.39
Feb	0.021	0.18	0.70	1.92	0.39
Mar	0.031	0.14	0.32	1.02	0.21
Apr	0.031	0.14	0.32	1.02	0.21
May	0.031	0.14	0.32	1.02	0.21
Jun	0.159	0.19	0.47	1.35	0.29
Jul	0.159	0.19	0.47	1.35	0.29
Aug	0.159	0.19	0.47	1.35	0.29
Sept	0.159	0.19	0.70	1.92	0.39
Oct	0.159	0.19	0.70	1.92	0.39
Nov	0.159	0.19	0.70	1.92	0.39
Dec	0.021	0.18	0.70	1.92	0.39

<u>Terrain Considerations</u>
For screening level analyses, the ODEQ requires terrain feature elevations to be included in the dispersion modeling analysis if the terrain within five kilometers of the stack rises to more than 20 percent of the shortest on-site stack being modeled. Since both stacks at the CFC are at base elevation of 622 feet above mean sea level (amsl) and a height of 505 ft, any terrain feature above 723 ft amsl within 5 km requires terrain feature elevations to be included in the dispersion modeling analysis. A review of the NED file within 5 km of the stacks results in terrain elevations above 723 ft; therefore, terrain feature elevations are represented in the dispersion modeling analysis. A NED file, obtained from the USGS representing a 50x50 km domain centered on the center of the two stacks at the CFC, is utilized in the dispersion modeling analysis to incorporate terrain features in AERSCREEN. Based on ODEQ's

suggested domain size for refined modeling analyses, a probe distance of 10 km is used in the AERSCREEN modeling analysis.

Urban/Rural Classification

The AERSCREEN model has the option of assigning the specified source to have an urban effect, thus enabling AERSCREEN to employ enhanced turbulent dispersion associated with anthropogenic heat flux, parameterized by population size of the urban area. Section 8.2.3 of the GAQM provides the basis for determining the urban/rural status of a source. For most applications, the land use procedure described in Section 8.2.3(c) is sufficient for determining the urban/rural status. However, there may be sources located within an urban area, but located close enough to a body of water to result in a predominantly rural classification. In those cases, the population density procedure may be more appropriate. Because the CFC facility is not located within an urban area near a body of water, only the following land use procedure is used to assess the urban/rural status of the source.

- Classify the land use within the total area, A_o, circumscribed by a 3-km radius circle about the source using the meteorological land use typing scheme proposed by Auer.
- If land use Types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (single-family compact residential), and R3 (multifamily compact residential) account for 50 percent or more of A_o, use urban dispersion coefficients; otherwise, use appropriate rural dispersion coefficients.

Based on visual inspection of the USGS 7.5-minute topographic map of the Project site location, it was conservatively concluded that over 50 percent of the area surrounding the Project may be classified as rural. Accordingly, the rural dispersion modeling option is used in the AERSCREEN model.

Minimum Ambient Distance

The AERSCREEN model allows the user to input the minimum distance to ambient air. Ambient air is defined in 40 CFR 50.1(e) as that portion of the atmosphere, external to buildings, to which the general public has access. Unit 2's stack is the closest to the facility's security boundary (i.e., that area to which public access is physically restricted); therefore, this distance is used as the minimum distance to ambient air in the AERSCREEN modeling analysis. For non-volume sources, which is the case for this Project, the AERSCREEN model cannot model an impact less than 1 meter; however, the CFC's minimum distance to ambient is 1,012 ft (308 m), as such, the 1,012 ft value is utilized in the modeling analysis.

Discrete and Flagpole Receptors

The AERSCREEN model allows the user to have the model calculate impacts at user defined discrete and/or flagpole receptors. Discrete receptors are those that are placed at precise locations that may be of interest due to their sensitive nature. Flagpole receptors are receptors that are located above ground level. The ODEQ Air Dispersion Modeling Guidelines does not mention the application of any discrete or flagpole receptors; therefore, no discrete or flagpole receptors are used in the modeling analysis.

Dispersion modeling analysis usually involves two distinct phases; a preliminary analysis and a full impact analysis. The preliminary analysis models only the significant increase in potential emissions of a pollutant from a proposed new source, or the significant net emissions increase of a pollutant from a proposed modification. The results of this preliminary analysis determine whether the applicant must perform a full impact analysis, involving the estimation of background pollutant concentrations resulting from existing sources and growth associated with the proposed Project. Specifically, the preliminary analysis:

- determines whether the applicant can forego further air quality analyses for a particular pollutant;
- may allow the applicant to be exempted from the ambient monitoring data requirements; and
- is used to define the impact area within which a full impact analysis must be carried out.

In general, the full impact analysis is used to project ambient pollutant concentrations against which the applicable NAAQS and PSD increments are compared, and to assess the ambient impact of non-criteria pollutants. The full impact analysis is not required for a particular pollutant when emissions of that pollutant would not increase ambient concentrations by more than the applicable significant impact level (SIL).

Because the AERSCREEN model used to perform the SIL analysis is a single source model, each unit was run individually. The resulting impacts were conservatively aggregated regardless of time and space to determine the Project's impact. The AERSCREEN model allows the applicant to choose from three different surface moisture categories for the Bowen ratio surface characteristic value, as discussed previously. All three surface moisture categories were modeled, and the Project's maximum model-predicted impacts are presented below. As the results indicate, the Project's model-predicted air quality impacts are less than the modeling significance levels, indicating that the Project is not subject to additional cumulative source air dispersion modeling analyses as part of the PSD review process.

Averaging Period and Scenario	Model-Predicted Impact (μg/m^3)			PSD Class II Significant Impact Level (μg/m^3)	PSD Class II Significant Monitoring Concentration (μg/m^3)
	Unit 1	Unit 2	Project		
8-hr average	126.5	155.0	281.5	500	575
8-hr dry	120.5	164.8	285.3		
8 hour wet	132.7	162.0	294.7		
1-hr average	140.6	172.2	312.8	2,000	--
1-hr dry	133.9	183.2	317.1		
1 hour wet	147.5	179.9	327.4		

C. Evaluation of PSD increment consumption

The model-predicted impact is less than the significant impact level; therefore, increment consideration is not necessary. In any event, there is no increment for CO.

D. Analysis of compliance with National Ambient Air Quality Standards (NAAQS)

The model-predicted impact is less than the significant impact level; therefore, further analysis is not necessary.

E. Ambient air monitoring
According to OAC 252:100-8-33(c), if the proposed project's maximum predicted concentration for a pollutant is less than the applicable PSD significant monitoring concentration, then an exemption from pre-application monitoring requirements can be requested for that pollutant. The preceding table shows that the maximum-modeled predicted CO 8-hour impact is less than the PSD significant monitoring concentration; therefore, the applicant requests exemption from PSD pre-application monitoring requirements.

F. Evaluation of source-related impacts on growth, soils, vegetation, visibility
The applicant provided an extensive review of source-related impacts on growth, soils, vegetation, and visibility as part of issuance of Permit No. 2009-179-C (M-2) PSD. The proposed change in the CO limit does not change this analysis.

G. Evaluation of Class I area impact
Federally designated Class I areas are afforded special protection in the air permitting process. Generally, Class I area analyses are conducted only for Projects located within 100 km of a Class I area. In this instance the closest Class I area is the 9,912-acre Upper Buffalo Wilderness Area (UBWA) in northwestern Arkansas. The UBWA is approximately 175 km from the facility. This is greater than the 50 km threshold and an analysis is not required.

The major concern at Class I areas is the degradation of visibility resulting from long-range transport of pollution from distant major sources. Based on the location of the facility and the pollutant of concern being impacted (CO), it is expected that there will be no visibility impacts on the UBWA.

SECTION VIII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations listed in OAC 252:100, Appendix Q. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards. In addition, proposed facility emissions modeled in the construction application demonstrate that the current project will not have a significant impact on air quality.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

a. 5 TPY of any one criteria pollutant
b. 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the Part 70 operating permit, from information in the construction permit application, or are developed from the applicable requirement.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for mitigation, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-19 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. Wall Boiler Unit 2 (B-02-2), the main igniter burners, Auxiliary Boilers No. 1, 2, and 3 (B-02-3, B-02-4, and B-02-5), Turbine Unit 3 (T-01-1), Emergency Generator Engines (EG-01-1, EG-02-2, and EG-03-3), and Fire Water Pump Engine (FP-03-1) are subject to the requirements of this subchapter. This subchapter specifies a PM emissions limitation of 0.6 lb/MMBTU from fuel-burning units with a rated heat input of 10 MMBTUH or less. For fuel-burning equipment greater than 10 MMBTUH, this subchapter specifies a PM emission limitation based upon the heat input of the equipment and is calculated according to the equations below:

$E = 1.042808\ X^{-0.238561}$ – For Units > 10 MMBTUH but < 1,000 MMBTUH
$E = 1.6\ X^{-0.30103}$ – For Units > 1,000 MMBTUH but < 10,000 MMBTUH

Where: E = allowable total particulate matter emissions in pounds per MMBTU and
X = the maximum heat input in MMBTU per hour.

The following table demonstrates compliance with the applicable emission limits for each fuel used based on the emissions from Section VI of the Memorandum.

Compliance Demonstration for Fuel-Burning Equipment with PM Emission Limits

Equipment	Maximum Heat Input, (MMBTUH)	Allowable Emission Rate, (lb/MMBTU)	Potential Emission Rate, (lb/MMBTU)
Wall Boiler Unit 2 (coal)	5,296	0.135	0.028
Aggregated Wall Boiler Unit 2 Igniters (nat. gas)	370	0.254	0.007
Aux Boilers No. 1 & 2 (nat. gas)	90	0.356	0.014
Aux Boiler No. 3 (nat. gas)	278	0.272	0.013
Turbine Unit 3 (nat. gas)	4,161	0.143	0.014
Emergency Generator 1	8.9	0.60	0.094
Emergency Generator 2	8.9	0.60	0.094
Emergency Generator 3	19.8	0.512	0.033
Fire Pump	3.1	0.60	0.277

Section 19-12 limits particulate emissions from new and existing directly fired fuel-burning units (and/or) emission points in an industrial process based on process weight rate, as specified in Appendix G. Allowable total particulate matter emission rates are calculated using the following formulas:

$E = 4.10\ P^{0.67}$ – For process weight rates ≤ 30 TPH
$E = (55\ P^{0.11}) - 40$ – For process weight rates > 30 TPH

Where: E = allowable total particulate matter emission rate in pounds per hour and
P = process weight rate in tons per hour.

There are numerous points in EUG 5 and EUG 6 that are subject to these standards. All points with identical throughput are lumped together to make the table more compact. Because some points have different control efficiencies, the highest emission rate from any of them is used to represent the group. Each set of points meets the requirements of Appendix G.

Compliance Demonstration for Processes Subject to PM Emission Limits

EU/Point	Process Rate (TPH)	Emissions (lb/hr)	
		App. G Limit	Potential
TO-03-01 & 02, CU-03-01	3,000	92.7	3.12
TO-03-03, 04, 05, 06, 07, 08	1,800	85.4	13.1

EU/Point	Process Rate (TPH)	Emissions (lb/hr)	
		App. G Limit	Potential
TO-03-09, 10, 11, 12, 13, 14	1,600	83.8	1.66
TO-03-15 & 16	2,250	88.6	4.68
TO-03-18, 19, 20, 21, 22, 23, 24, 25	800	74.7	8.32
TO-03-30, 31	16	26.3	0.01
BL-06-01	45	43.6	-0-
BU-06-01, FL-05-01, FU-05-01	3,500	95.0	3.00
LU-04-01	15	25.2	0.01
T-03-32, 33	0.065	0.66	0.046

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. Units subject to an opacity limit promulgated under section 111 of the Federal Clean Air Act are exempt from this section. Wall Boiler Unit 2 (B-02-2) is subject to NSPS Subparts Da and is exempt from these requirements per §25-3(a). Coal handling equipment subject to Subpart Y is also exempt. Turbine Unit 3 (T-01-1), Auxiliary Boilers No. 1, 2, and 3 (B-02-3, B-02-4, and B-02-5), Emergency Generator Engines (EG-01-1, EG-02-2, EG-03-3), Fire Pump Engine (FP-03-1) and Materials Handling (EUG 6) equipment remain subject to the opacity standard. When burning natural gas or diesel fuel for short periods, there is little possibility of exceeding the opacity standards. Turbine Unit 3 (T-01-1), Auxiliary Boilers No. 1, 2, and 3 (B-02-3, B-02-4, and B-02-5), Emergency Generator Engines (EG-01-1, EG-02-2, EG-03-3), and Fire Pump Engine (FP-03-1) will assure compliance with this rule by ensuring "complete combustion."

The Material Handling Equipment (EUG6): fly ash silos, lime building baghouse, and PAC silos will assure compliance with the rule by maintaining the filters and baghouses in accordance with manufacturer's requirements and will demonstrate compliance through monitoring of the baghouse pressure differentials.

Continuous Opacity Monitoring (COM) is required for fossil fuel-fired steam generators in accordance with paragraph 2.4 of 40 CFR Part 51, Appendix P. This also applies to any fuel-burning equipment with a design heat input value of 250 MMBTUH or more, that does not burn gaseous fuel exclusively, and that was not in being on or before July 1, 1972, or that is modified after July 1, 1972. 40 CFR Part 51, Appendix P exempts fossil fuel-fired steam generators from the COM requirements when gaseous fuel is the only fuel burned. This requirement does not apply to sources subject to a NSPS. The steam generator Wall Boiler Unit 2 (B-02-2) is subject to NSPS and is not subject to this rule. Since Turbine Unit 3 (T-01-1) and Auxiliary Boilers No. 1, 2, and 3 (B-02-3, B-02-4, and B-02-5) will only burn natural gas, they are exempt from the COM requirements.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or allow the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with

the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards.

No person shall cause or allow any fugitive dust source to be operated, or any substances to be handled, transported or stored without taking reasonable precautions to minimize or prevent pollution. Reasonable precautions may include, but are not be limited to, the following:

a. The use, where possible, of water or chemicals for control of dust on roads, driveways and parking lots;
b. The application of water or suitable chemicals or some other covering on materials stockpiles and other surfaces that can create air-borne dusts under normal conditions;
c. The installation and use of hoods, fans and dust collectors to enclose and vent the handling of dusty materials or the use of water sprays or other acceptable measures to suppress dust emission during handling;
d. The covering or wetting of open-bodied trucks, trailers, or railroad cars when transporting dusty materials in areas where the general public must have access;
e. The removal as necessary from paved street and parking surfaces of materials that have a tendency to become airborne; and
f. The planting and maintenance of vegetative ground cover as necessary.

Reasonable precautions have been incorporated into the permit. The facility has instituted measures to minimize emissions from vehicular traffic such as paving roads and parking areas where possible, use of wetting agents on unpaved roadways, and periodic sweeping of paved roads. Fugitive dust emissions caused by coal, ash, and activated carbon handling and processing are minimized by use of collection and venting of emissions to fabric filters where possible and confining the active disturbance to a small areas.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air concentration of hydrogen sulfide (H_2S) emissions from any facility to 0.2 ppmv (24-hour average) at standard conditions which is equivalent to 283 ug/m^3. Fuel-burning equipment fired with commercial natural gas will not have the potential to exceed the H_2S ambient concentration limit.
Part 5 limits sulfur dioxide emissions from new fuel-burning equipment (constructed after July 1, 1972). For natural gas or other gaseous fuels, the limit is 0.2 lb/MMBTU heat input, three-hour average. The Wall Boiler Unit 2's (B-02-2) ignitor burner, Auxiliary Boilers No. 1-3 (B-02-3, B-02-4, B-02-5), and Turbine Unit 3 (T-01-1) combust commercial grade natural gas with emissions of 0.014 lb/MMBTUH which is in compliance with this subchapter. The emissions are based on a fuel sulfur content of 5 gr/100 scf, a fuel heat content of 1,020 BTU/scf, and 100% conversion of sulfur to sulfur dioxide. The permit requires Wall Boiler Unit 2 (B-02-2) ignitor burner, Auxiliary Boilers No. 1 and 2 (B-02-3 and B-02-4), Turbine Unit 3 (T-01-1), and Auxiliary Boiler No. 3 (B-02-5) to be fired with commercial grade natural gas with a maximum fuel sulfur content of 5 gr/100 scf.

For liquid fuels, the limit is 0.8 lb/MMBTU heat input, three-hour average. The Emergency Generator Engines (EG-01-1, EG-02-2, and EG-03-3) and Fire Pump Engine (FP-01-1) are limited to combustion of ultra-low sulfur diesel fuel with a maximum sulfur content of 0.015% by weight sulfur and emissions of 0.015 lb/MMBTUH which is in compliance with this subchapter. The emissions are based on the given fuel sulfur content and the AP-42 (10/96), Section 3.4 SO_2 emission factor. The permit requires the Emergency Generator Engines (EG-01-1, EG-02-2, and EG-03-3) and Fire Pump Engine (FP-01-1) to comply with either NESHAP, Subpart ZZZZ or NSPS, Subpart IIII which limits the fuel sulfur content to 15 ppmw.

For solid fuels, the limit is 1.2 lb/MMBTU heat input, three-hour average. Wall Boiler Unit 2 (B-02-2) has current SO_2 emissions of 0.20 lb/MMBTU. The permit limits SO_2 emissions from Wall Boiler Unit 2 (B-02-2) when burning coal to levels below 1.2 lb/MMBTU and compliance with the limit to be demonstrated using CEMS data.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]

This subchapter limits NO_X emissions from new fuel-burning equipment with a rated heat input of 50 MMBTUH or greater. For natural gas or other gaseous fuels, the limit is 0.2 lb/MMBTU heat input, three-hour average. For liquid fuels, the limit is 0.3 lb/MMBTU heat input, three-hour average. For solid fuels, the limit is 0.7 lb/MMBTU heat input, three-hour average. New fuel-burning equipment means any fuel-burning equipment that was not in being on February 14, 1972, any gas turbine not in being on July 1, 1977, or any existing fuel-burning equipment that was altered, replaced, or rebuilt. The following table demonstrates compliance with the applicable emission limits for each fuel used based on the emissions from Section V.

Compliance Demonstration for
Fuel-Burning Equipment Subject to NO_X Emission Limits

Source EU/Point	Heat Input (MMBTUH)	Fuel	SC 33 Limit (lb/MMBTU)	Emission Factor (lb/MMBTU)
Wall Boiler Unit 2 B-02-2	5,296	Coal	0.7	0.31
Auxiliary Boiler No. 1 B-02-3	90	Gas	0.2	0.04
Auxiliary Boiler No. 2 B-02-4	90	Gas	0.2	0.04
Auxiliary Boiler No. 3 B-02-5	278	Gas	0.2	0.04
Turbine Unit 3 T-01-1	4,161	Gas	0.2	0.06

Coal-fired NO_X emissions are guaranteed by the LNB/OFA equipment manufacturer at 0.3 lb/MMBTU (30-day rolling average) for Wall Boiler Unit 2 (B-02-2), and should easily satisfy the 0.70 lb/MMBTU (3-hour average) standard. The permit limits NO_X emissions from Wall Boiler Unit 2 (B-02-2) when burning coal to levels below 0.7 lb/MMBTU and requires compliance with the limit to be demonstrated using a CEMS data. The permit limits Turbine Unit 3 (T-01-1) to below the 0.2 lb/MMBTU limit and requires compliance with the limit to be demonstrated using CEM data. Auxiliary Boilers No. 1, 2, and 3 (B-02-3, B-02-4, and B-02-5) are limited use units with emissions factors significantly lower than the NO_X limits and it is not economical to monitor emissions.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
None of the following affected processes are located at this facility: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Parts 3 and 7 applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The 6,000-gallon gasoline tank is equipped with a submerged fill pipe. Fuel oil and lube oil have vapor pressures below 1.5 psia, and are not affected facilities.
Part 5 limits the VOC content of coating used in coating lines or operations. This facility will not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is not an affected operation.
Part 7 requires fuel-burning equipment to be cleaned, operated, and maintained so as to minimize emissions of VOC. Based on manufacturer's data and good engineering practice, the equipment must not overloaded and temperature and available air must be sufficient to provide essentially complete combustion. Extensive monitoring of emissions from the electric generating units (EGUs) is performed, and is adequate to assure compliance with the requirements of OAC 252:100-37-36. All fuel burning equipment at this facility are designed to provide essentially complete combustion of VOC.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates TAC that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

Each emissions unit was evaluated for periodic testing in accordance with the Periodic Testing Standardization guidance issued December 1, 2011, on a pollutant by pollutant basis. The frequency of the periodic testing requirement is based on the quantity of the pollutant emitted. Periodic testing requirements are not required for an emission unit that is subject to an applicable requirement that already requires periodic testing or CEM. For this facility, only pollutants greater than 40 TPY for each emission unit were evaluated.

Periodic Testing Review

EU/Point	Pollutant	TPY	Current Monitoring	Periodic Testing
B-02-2	NO_X	11,598	Part 60/75 CEMS	N/A
B-02-2	SO_2	13,915	Part 60/75 CEMS	N/A
B-02-2	CO	6,263	None	YES - Every Year
B-02-2	PM_{10}	646	Opacity	N/A[a]
B-02-2	VOC	81	None	N/A[b]
T-01-1	NO_X	1,093	Part 60/75 CEMS	NO
T-01-1	SO_2	273	Part 75 Fuel Testing	NO
T-01-1	CO	583	None	YES - Every Year
T-01-1	PM_{10}	255	None	N/A[c]
T-01-1	VOC	73	None	N/A[b]

[a] - PM emissions were previously correlated to opacity and is currently used to comply with CAM.
[b] - The uncontrolled PTE is < 100 TPY and additional testing is not warranted.
[c] - Natural gas fired emission unit and additional testing is not warranted.

CO testing for the coal-fired boiler and natural gas-fired combined cycle combustion turbine is established in the operating permit.

Oklahoma Air Pollution Control Rules Not Applicable to this Facility

OAC 252:100-7	Minor Facility Permits	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Motor Vehicle Control Devices	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain, Feed or Seed Operations	not in source category
OAC 252:100-39	Nonattainment Areas	not in a subject area
OAC 252:100-47	MSW Landfills	not in source category

SECTION IX. FEDERAL REGULATIONS

Protection of Visibility, 40 CFR 51 Subpart P [Applicable]
The primary purposes of this subpart are to require States to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution; and to establish necessary additional procedures for new source permit applicants, States and Federal Land Managers to use in conducting the visibility impact analysis required for new sources under §51.166. This subpart sets forth requirements addressing visibility impairment in its two principal forms: “reasonably attributable” impairment (i.e., impairment

attributable to a single source/small group of sources) and regional haze (i.e., widespread haze from a multitude of sources which impairs visibility in every direction over a large area). Regional haze visibility impairment is partially addressed through the Best Available Retrofit Technology (BART) process. The emission units at this facility do not meet the definition of BART-eligible sources.

PSD, 40 CFR Part 52 [Applicable]
This facility is one of the 26 listed facilities with major source threshold of 100 TPY. Total potential emissions of NO_X, CO, SO_2, VOC, and PM_{10} are greater than the major source threshold of 100 TPY. The Grand River Energy Center is a major stationary source and the proposed construction permit is subject to New Source Review. The facility is in an attainment area and is required to undergo analysis if the project is a significant modification. The analysis is located in Section VII of this Memorandum.

NSPS, 40 CFR Part 60 [Subparts A, Da, Db, Y, IIII, and KKKK are Applicable]
Subpart A, General Provisions. This subpart establishes notification, recordkeeping, and reporting requirements, performance test requirements, compliance and maintenance requirements, monitoring requirements and control device and work practice requirements for NSPS-affected facilities.

Subpart D, Fossil-Fuel-Fired Steam Generators. This subpart affects fossil-fuel-fired steam generating units with a design heat input capacity greater than 250 MMBTUH that commenced construction or modification after August 17, 1971. The 5,400-MMBTUH Wall Boiler Unit 1 (B-02-1) has been permanently decommissioned. The 5,296-MMBTUH Wall Boiler Unit 2 (B-02-2) is an affected source under NSPS Subpart Da; therefore, it is exempt from this subpart.

Subpart Da, Electric Utility Steam Generating Units. This subpart affects electric utility steam generating unit capable of combusting more than 250 MMBTUH that commenced construction, modification, or reconstruction after September 18, 1978. Wall Boiler Unit 2 (B-02-2) has heat input capacity of 5,296 MMBTUH, commenced construction on March 24, 1982, and is an affected source.

The update of the CO emission factor for Wall Boiler Unit 2 (B-02-2) did not replace any components or change the method of operation. Therefore, Wall Boiler Unit 2 (B-02-2) is not considered reconstructed or modified. Updating the CO emission factor did not increase emissions of PM, SO_2, or NOx, which are the only pollutants subject to regulation under this subpart. The applicable standards to be met by Wall Boiler Unit 2 (B-02-2) are:

a. § 60.42Da(a) establishes a PM emission limit of 0.03 lb/MMBTU for any unit that commenced construction, reconstruction, or modification before March 1, 2005, and prohibits opacity in excess of 20% (6-minute average), except for one six-minute period per hour of not more than 27% opacity.
b. § 60.43Da(a) establishes a SO_2 emission limit of 1.2 lb/MMBTU (30-day rolling average) and a 90% reduction of the potential combustion concentration from any unit that commenced construction, reconstruction, or modification before February 28, 2005, in

which solid fuel or solid-derived fuel is combusted or a 70% reduction of the potential combustion concentration when emissions are less than 0.60 lb/MMBTU.

c. § 60.44Da(a) establishes a NO_X emission limit of 0.60 lb/MMBTU (30-boiler operating day rolling average) from any unit that commenced construction, reconstruction, or modification before July 10, 1997, which combusts bituminous coal or 0.50 lb/MMBTU when combusting sub-bituminous coal. The standard is pro-rated in the instance of simultaneous combustion of different fuels.

Compliance with the limits set in §§ 60.42Da, 60.43Da, and 60.44Da was established by initial performance testing. Ongoing compliance with the opacity standard and SO_2 and NO_X emission standards is demonstrated through use of a COMS and a CEMS. All applicable requirements are incorporated into the permit.

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity greater than 100 MMBTUH that commenced construction, modification, or reconstruction after June 19, 1984. Auxiliary Boiler No. 3 (B-02-5) has a heat input capacity of 278 MMBTUH commenced construction on after June 19, 1984, and is an affected source. Since Auxiliary Boiler No. 3 (B-02-5) only combusts natural gas it is not subject to a PM or SO_2 standard. Additionally, Auxiliary Boiler No. 3 (B-02-5) will not run more than 10 percent capacity factor on an annual average basis; therefore, it is exempt from § 60.44b(l).

Low heat release means a heat release rate of 70,000 BTU/hr-ft^3. Compliance with the limit in § 60.44b was established by initial performance testing. All applicable requirements are incorporated into the permit.

Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a maximum design heat input capacity between 10 and 100 MMBTUH that commenced construction, modification, or reconstruction after June 9, 1989. Auxiliary Boilers No. 1 and 2 (B-02-3 and B-02-4) were constructed prior to June 9, 1989, and have not been modified or reconstructed. The Auxiliary Boiler No. 3 (B-02-5) has a design heat capacity greater than 100 MMBTUH. Therefore, Auxiliary Boilers No. 1, 2, and 3 (B-02-3, B-02-4, and B-02-5) are not subject to this subpart.

Subparts K & Ka, Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to July 23, 1984. These subparts affect petroleum liquid storage vessels which have a capacity greater than 40,000 gallons. The 150,000-gallon diesel storage tank exceeds the 40,000-gallon thresholds of K and Ka, but they contain No. 2 fuel oil, which is specifically excluded from each subpart. The 10,000-gallon diesel and gasoline tanks used for service vehicles are smaller than 40,000 gallons and are not affected sources under these subparts.

Subpart Kb, Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. None of the tanks were constructed after the effective date of Subpart Kb.

Subpart GG, Stationary Gas Turbine. This subpart affects stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBTUH, based on LHV of the fuel fired, that commenced construction, modification, or reconstruction after October 3, 1977. The Turbine Unit 3 (T-01-1) is exempt from this subpart per § 60.4305(b) under Subpart KKKK.

Subpart Y, Coal Preparation and Processing Plants. This subpart applies to affected facilities in coal preparation and processing plants that commenced construction, reconstruction, or modification after October 27, 1974, that process more than 200 tons per day (TPD). The following equipment that commenced construction, reconstruction, or modification after October 27, 1974, but before April 28, 2008: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems, are subject to the provisions of §§ 60.251, 60.252(a), 60.253(a), 60.254(a), 60.255(a), and 60.256(a). After May 27, 2009, affected facilities includes open storage piles and requires fugitive coal dust emissions control plans. This facility does not have thermal dryers or pneumatic coal-cleaning equipment. All equipment at this facility was constructed prior to April 28, 2008, and has not been reconstructed or modified. EUG 5 and EUG 7 contains all of the affected facilities and the applicable standard to be met are:

a. § 60.254(a) establishes a 20% opacity limit for coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal; and
b. § 60.255(a) requires all performance tests to demonstrate compliance with the applicable emission standards to be done using the methods identified in § 60.257.

Compliance with the opacity limits is demonstrated through opacity readings conducted in accordance with Method 9. All applicable requirements are incorporated into the permit.

Subpart OOO, Nonmetallic Mineral Processing Plants. This subpart applies to affected facilities at nonmetallic mineral processing plants. The provisions of this subpart do not apply to plants without crushers or grinding mills above ground. Although the facility processes lime for the FGD, it is not an affected source because it has no crushers or grinding mills above ground.

Subpart IIII, Stationary Compression Ignition Internal Combustion Engines (CI-ICE). This subpart affects stationary CI-ICE based on power and displacement ratings, depending on the date that construction commences, beginning with those constructed after July 11, 2005. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator. The two 1,190-hp Emergency Generator Engines (EG-01-1 and EG-02-2) and the 390-hp Fire Pump Engine (FP-03-1) were installed prior to July 11, 2005, and are not affected facilities. The 2,922-hp Emergency Generator Engine (EG-03-3) was constructed after July 11, 2005, and is an affected facility. Emergency Generator Engine (EG-03-3) is diesel-fired, has a displacement of less than 30 liters, and is subject to the following emission limitations:

a. § 60.4202(a)(2) establishes emission standards for emergency stationary CI-ICE with a maximum engine power less than or equal to 3,000-hp and a displacement of less than 10 L/Cylinder as the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in §§ 89.112 and 89.113 for all pollutants beginning in model year 2007.

Tier 2 (> 2006) Emission Limits for Emergency Engines > 750-hp

Units	NMHC + NO_X	CO	PM
g/kW-hr	6.4	3.5	0.20
g/hp-hr	4.8	2.6	0.15

Opacity Limits

Mode	Opacity
Acceleration	20%
Lugging	15%
Peak	50%

b. In addition, the emergency stationary CI-ICE must comply with the operating limitations of § 60.4211(f)(1)-(3).

Compliance with the emission limits were demonstrated by purchasing a certified engine that was installed and configured according to manufacturer's specifications. Continuous compliance with the standards is achieved by operating and maintaining the engine and control device in accordance with the manufacturer's emission-related written instructions, changing only those emission-related settings permitted by the manufacturer, and meeting the requirements of 40 CFR Part 89. All applicable requirements of this subpart are incorporated into the permit.

Subpart JJJJ, Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart affects stationary SI-ICE ordered after June 12, 2006 and all stationary SI-ICE engines modified or reconstructed after June 12, 2006, regardless of size. There are no stationary SI-ICE at this facility.

Subpart KKKK, Stationary Combustion Turbines. This subpart affects stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBTUH, based on HHV of the fuel fired, that commenced construction, modification, or reconstruction after February 18, 2005. Stationary combustion turbines regulated under this subpart are exempt from the requirements of Subpart GG. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of Subparts Da, Db, and Dc. Turbine Unit 3 (T-01-1) has a heat input at peak load greater than 10 MMBTUH and is an affected facility. The applicable standards to be met by Turbine Unit 3 (T-01-1) are:

a. § 60.4320(a) establishes a NO_X emission limit of 15 ppmdv @ 15% O_2 or 0.43 lb/MWh for natural gas fired, electric generating combustion turbines with a heat input at peak load of greater than 850 MMBTUH.
b. § 60.4330(a) establishes a SO_2 emission limit of 0.06 lb/MMBTU or 0.90 lb/MWh.

Compliance with the NO_X emission limit in § 60.4320 was established by initial CEM certification. Compliance with the SO_2 emission limit in § 60.4330 was established using a fuel contract specifying a total sulfur content less than 20 gr/100 scf. Ongoing compliance with the NO_X standard is demonstrated through use of a CEMS. All applicable requirements are incorporated into the permit.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are small emissions of some pollutants regulated by Part 61, including 0.05 lb/hr and 0.33 TPY of arsenic, 0.80 lb/hr and 0.49 TPY of benzene, 0.02 lb/hr and 0.09 TPY of beryllium, and 0.10 lb/hr and 0.42 TPY of mercury.
Subparts N, O, and P Inorganic Arsenic from Glass Manufacturing Plants, Primary Copper Smelters, and Arsenic Trioxide and Metallic Arsenic Production Facilities. Electric generating facilities are not an affected source under any of these subparts.
Subparts C and D, Beryllium and Beryllium Rocket Motor Firing. Electric generating facilities are not an affected source under either of these subparts.
Subpart E, Mercury. Electric generating facilities are affected sources only if they incinerate or dry wastewater treatment plant sludge. This facility does not incinerate or dry wastewater treatment plant sludge and is not an affected facility.
Subparts J, L, Y, BB, and FF, Benzene. Electric generating facilities and boilers are not affected sources under these subparts.

NESHAP, 40 CFR Part 63 [Subparts YYYY, ZZZZ, DDDDD, and UUUUU are Applicable]
Subpart Q, Industrial Process Cooling Towers. This subpart affects industrial process cooling towers that are operated with chromium-based water treatment chemicals and are major sources of HAP or are integral parts of a facility which is a major source of HAP. This facility has never used chromium-based water treatment chemicals.

Subpart YYYY, Stationary Combustion Turbines. This subpart affects stationary combustion turbines that are located at a major source of HAP. On August 18, 2004, the EPA stayed the effectiveness of two subcategories of this subpart: lean premix gas-fired stationary combustion turbines and diffusion flame gas-fired stationary combustion turbines pending the outcome of EPA's proposal to delete these subcategories from the source category list. This facility is a major source but Turbine Unit 3 (T-01-1) is in the lean premix gas-fired stationary combustion turbine and diffusion flame gas-fired stationary combustion turbine categories and is expected to be deleted from the source category list. It was required to comply with the initial notification requirements set forth in § 63.6145 but does not need to comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines):

a. Stationary RICE located at an area source;
b. The following Stationary RICE located at a major source of HAP emissions:
   i) 2SLB and 4SRB stationary RICE with a site rating of ≤ 500 brake HP;
   ii) 4SLB stationary RICE with a site rating of < 250 brake HP;
   iii) Stationary RICE with a site rating of ≤ 500 brake HP which combust landfill or digester gas equivalent to 10% or more of the gross heat input on an annual basis;
   iv) Emergency or limited use stationary RICE with a site rating of ≤ 500 brake HP; and

v) CI stationary RICE with a site rating of ≤ 500 brake HP.

No further requirements apply for engines subject to NSPS under this part. This facility is a major source of HAP. RICE > 500-hp located at a major source are new or reconstructed if construction or reconstruction commenced after December 19, 2002. RICE ≤ 500-hp located at a major source are new or reconstructed if construction or reconstruction commenced after June 12, 2006. The 2,922-hp Emergency Generator Engine (EG-03-3) falls into the new category of engines and is only subject to the requirements of NSPS, Subpart IIII.

The following existing stationary RICE at major sources do not have to meet the requirements of this subpart and of Subpart A of this part, including initial notification requirements:

a. Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating > 500-hp;
b. Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating > 500-hp;
c. Existing emergency stationary RICE with a site rating > 500-hp that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).
d. Existing limited use stationary RICE with a site rating > 500-hp; and
e. Existing stationary RICE with a site rating of > 500-hp that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

The two 1,190-hp Emergency Generator Engines (EG-01-1 and EG-02-2) and 390-hp Fire Pump Engine (FP-03-1) are considered existing units and are emergency or limited use stationary RICE. The two 1,190-hp Emergency Generator Engines (EG-01-1 and EG-02-2) are exempt from this subpart except for notification, per 40 CFR § 63.6590(b)(3)(iii).

The 390-hp Fire Pump Engine (FP-03-1) is subject to this subpart. A summary of the requirements for the limited use CI RICE are shown below.

RICE Category	Emission Limit/Operating Limits[1]
Emergency CI RICE[2]	Change oil and filter every 500 hours of operation or annually, whichever comes first;[3]
	Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
	Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary[4].

[1] During periods of startup you must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[4]

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of Subpart ZZZZ, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[3] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of Subpart ZZZZ.

[4] Sources can petition the Administrator pursuant to the requirements of 40 CFR § 63.6(g) for alternative work practices.

All applicable requirements have been incorporated into the permit.

Subpart DDDDD, Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters. This subpart establishes emission limitations and work practice standards for industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. The compliance dates for the rule were January 31, 2016, for existing sources and, January 31, 2013, or upon startup, whichever is later, for new sources.

A boiler or process heater is new or reconstructed if construction or reconstruction of the boiler or process heater commenced on or after June 4, 2010. Auxiliary Boiler No. 3 (B-02-5) is considered new boiler. All other boilers (B-02-02 through B-02-04) are considered existing boilers. EGU covered by Subpart UUUUU are not subject to this subpart. Wall Boiler Unit 2 (B-02-2) as a coal-fired unit is subject to Subpart UUUUU and is not subject to this subpart.

Unit(s) designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory must complete a tune-up initially and periodically as indicated below and as specified in § 63.7540:

Heat Input Capacity	**Period**
≤ 5 MMBTUH	Every 5 Years
> 5 MMBTUH & < 10 MMBTUH	Every 2 Years
≥ 10 MMBTUH W/O Continuous Oxygen Trim System	Annually
≥ 10 MMBTUH W/Continuous Oxygen Trim System	Every 5 Years

Units in the gas 1 subcategory will conduct these tune-ups as a work practice for all regulated emissions under Subpart DDDDD. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 of Subpart DDDDD, or the operating limits in Table 4 of Subpart DDDDD. Auxiliary Boiler No. 1 (B-02-3), Auxiliary Boiler No. 2 (B-02-4), and Auxiliary Boiler No. 3 (B-02-5) are subcategorized as units designed to burn gas 1 fuels. They will be required to comply upon startup. Auxiliary Boiler No. 1 (B-02-3), Auxiliary Boiler No. 2 (B-02-4), and Auxiliary Boiler No. 3 (B-02-5) will be required to have tune-ups as indicated in this subpart.

Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 of Subpart DDDD, the annual tune-up, or the energy assessment requirements in Table 3 of Subpart DDDDD, or the operating limits in Table 4 of Subpart DDDDD. Limited-use boiler or process heater means any boiler or process heater that has a federally enforceable average annual capacity factor of no more than 10 percent.

Waste heat boilers are excluded from the definition of boiler. Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas. The duct burners associated with the waste heat boilers are not subject to this subpart.

Existing boilers and process heaters located at a major source facility, not including limited use units must have a one-time energy assessment performed by a qualified energy assessor. All applicable requirements of this subpart are incorporated into the permit.

Subpart UUUUU, Coal- and Oil-Fired Electric Utility Steam Generating Units (EGU). This subpart affects EGU that combust coal or oil. This MACT is also known as Mercury and Air Toxics Standards (MATS). The compliance date for Wall Boiler Unit 2 (B-02-2) is April 16, 2016, because the applicant has requested and received a one-year extension. Wall Boiler Unit 2 (B-02-2) fits the definition of coal-fired EGU as defined in § 63.10042. Emission limits are found in Table 2 to Subpart UUUUU, Subcategory 1. Wall Boiler Unit 2 (B-02-2) is required to select from one of the following options: a filterable PM emission limit of 3.0E-2 lb/MMBTU, a total non-Hg HAP metals emission limit of 5.0E-5 lb/MMBTU, or ten individual HAP metals (Sb, As, Be, Cd, Cr, Co, Pb, Mn, Ni, Se) emission limits. Wall Boiler Unit 2 (B-02-2) is also required to select either an HCl emission limit of 2.0E-3 lb/MMBTU or an SO_2 emission limit of 2.0E-1 lb/MMBTU for control of acid gases. Finally, each coal-fired EGU will have to comply with either a 30-day average Hg emission limit of 1.2 lb/TBTU or a 90-day average Hg emission limit of 1.0 lb/TBTU. Table 3 to Subpart UUUUU establishes work practice standards including tune-up frequency and requirements that apply during startup and shutdown periods. Requirements in Tables 4 through 9 and Appendices A and B to Subpart UUUUU depend on the selections made by the facility in Tables 2 and 3 to Subpart UUUUU.

Subpart CCCCCC, Gasoline Dispensing Facilities. This subpart establishes emission limitations and management practices for HAP emitted from the loading of gasoline storage tanks at gasoline dispensing facilities (GDF) located at an area source. GDF means any stationary facility which dispenses gasoline into the fuel tank of a motor vehicle. This facility is a major source and the GDF at this facility is not subject to the requirements of this subpart.

Subpart JJJJJJ, Industrial, Commercial and Institutional Boilers and Process Heaters affects boilers at area sources of HAP. This facility is a major source, so the boilers are affected sources under Subpart DDDDD, but not under JJJJJJ.

Compliance Assurance Monitoring (CAM), 40 CFR Part 64 [Applicable]
CAM applies to any pollutant specific emission unit (PSEU) at a major source, which is required to obtain a Title V permit, if it meets all of the following criteria:

a. It is subject to an emission limit or standard for an applicable regulated air pollutant (RAP).
b. It uses a control device to achieve compliance with the applicable emission limit or standard.

c. It has potential emissions, prior to the control device, of the applicable RAP greater than major source levels.

The following table lists all emission units that have emissions of a RAP greater than the major source levels, the applicable RAP, if the emission unit is subject to an emission limit for the RAP, and if the PSEU is subject to CAM for the applicable RAP.

CAM Applicability Review

PSEU	RAP	TPY	Control Device	Current Monitoring	CAM
Wall Boiler Unit 2	NO_X	11,598	NO (a)	Part 60/75 CEMS	N/A
	SO_2	13,915	YES	Part 60/75 CEMS	N/A (b)
	CO	3,943	NO	None	N/A
	PM_{10}	646	YES	Opacity	YES (c)
	HCl	17	YES	Part 63 - NESHAP	N/A (d)
Turbine Unit 3	NO_X	1,093	NO (a)	Part 60/75 CEMS	N/A
	SO_2	273	NO	Part 75 Fuel Testing	N/A
	CO	583	NO	None	N/A
	PM_{10}	255	NO	None	N/A

(a) Control devices do not include passive control measures that act to prevent pollutants from forming.
(b) CAM does not apply to emission limitations or standards for which a Part 70 permit specifies a continuous compliance determination method.
(c) PM emissions are correlated to opacity and used to comply with CAM.
(d) CAM does not apply to emission limitations or standards proposed after November 15, 1990 pursuant to section 111 (NSPS) or 112 (NESHAP) of the Clean Air Act.

CAM is required for Wall Boiler Unit 2 (B-02-2). Wall Boiler Unit 2 (B-02-2) has PM emissions greater than the major source threshold and are required to collect for the parameter(s) monitored four or more data values equally spaced over each hour. Use of a COMS that satisfies the monitoring requirements of Appendix B of Part 60 satisfies the CAM general design criteria. A COMS is required to establish indicator ranges in accordance with § 64.3(a) and reporting requirements for excursions based on the applicable averaging period.

EPA-sponsored studies have failed to establish an absolute relationship between actual PM emission rates and a certified opacity monitor. As a result, EPA requires that CAM establish a reasonable assurance of compliance with the PM standard, rather than an absolute continuous measurement of PM. EPA published a paper comparing various PM emission rates with opacity for an actual test of a coal-fired boiler (*Proposed Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal Fired Boiler*, April 2003). The boiler tested had a PM limit of 0.24 lb/MMBTU, much higher than the limit for the GRDA boiler. Jahnke (*Continuous Emission Monitoring*, Second Edition) and EPA's Environmental Research Lab (Conner, Knapp, and Nader, 1979) have demonstrated a relationship between opacity and particle concentration using Bouger's Law. The mathematical relationship is stated as:

$$Tr = e^{-naQl}$$

Where:
Tr = transmittance = (100 – opacity %) ÷ 100,
n = number of particles,
a = area of the particles,
Q = light extinction coefficient, and
l = path length.

The analysis assumes that particle size is constant, or that the distribution of size does not vary dramatically over time, and that stack flows are relatively constant. The light extinction coefficient should be reasonably constant and path length (stack diameter) is constant. Given these assumptions, the combination of a, Q, and l may be treated as a single constant, C, and the equation reduces to:

$$Tr = e^{-nC}$$

It is reasonable to assert that n is linear with lb/MMBTU, so actual test values can be inserted for opacity and concentration, and the equation may be solved for C. At this point, a desired lb/MMBTU standard or limit may be inserted for the independent variable and the related opacity determined. This summarizes the principle to be used in determining indicator values for the two units. Voltage and current levels for the ESP stages are recorded and reviewed as if they are secondary indicators, but regular inspections of the ESP to assure normal operations are the main thrust of efforts to maintain compliance.

Mostardi Platt performed initial stack testing on December 2/3, 1981, that showed opacity of 16% coincident with PM emissions of 0.037 lb/MMBTU. This result is deemed to be significant for the reasons that the 16% datum is close to the upper opacity limit of 20% and the 0.037 lb/MMBTU datum is between the upper limits for Wall Boiler Unit 2. The facility considered these two data points in three different contexts to determine appropriate indicator values.

a. The first context reviewed was the EPA test mentioned above. As noted earlier, this test concerned units with PM emissions well above those authorized for the GRDA units, and testing occurred at actual emission levels up to approximately one order of magnitude above the authorized limit for GRDA Wall Boiler Unit 2. The linearity expectation discussed above was observed over the range of emissions at GRDA, but a curve fit program applied to the data indicates a second linear relationship for data points above the GRDA range of values. Using only the curve fit technique, without appeal to the mathematical analysis, yields a 12% opacity at the Unit 2 limit of 0.028 lb/MMBTU.
b. The second context reviewed was the linear method described in A(i). Using the values of Tr = 100% - 16% and 0.037 lb/MMBTU as a surrogate for n, C is determined to be 4.843. Solving now for values of 0.1 and 0.028 lb/MMBTU yields an opacity value of 13% for Wall Boiler Unit 2.
c. The third context reviewed was contained in an analysis of a CAM plan for a DEQ-permitted Hugo coal-fired plant. In that instance, C was determined to be 7.672, which would yield an opacity limit of 19% for Wall Boiler Unit 2.

Reviewing these three contexts and adding a fourth standard based on GRDA operational experience as to levels they consider significant, yields the following table of values.

Method	**Maximum Opacity to Meet the PM Standard**
	Wall Boiler Unit 2
EPA Test Data	12%
GRDA "Linear" Analysis	13%
Using Hugo Equation	19%
GRDA Experience	11%

Based on this table, the facility has determined an indicator level of 12% for Wall boiler Unit 2 (B-02-2). However, the change from ESP to fabric filter will require that a new CAM plan be prepared for Wall Boiler Unit 2 (B-02-2). All applicable requirements have been incorporated into the permit.

Accidental Release Prevention, 40 CFR Part 68 [Applicable]
The facility uses commercial natural gas fuel, which is comprised of mainly methane, a listed substance in CAAA 90 Section 112(r). However, this substance is not stored on site. The small quantity that is in the pipelines on the facility is much less than the 10,000-pound threshold and therefore is excluded from all requirements including the Risk Management Plan (RMP). Similarly, the facility has maximum storage capacity of 886 pounds of hydrogen, well below the threshold of 10,000 pounds, and hydrogen is excluded from this requirement. The facility does not store sufficient quantities of chlorine or aqueous ammonia to require an RMP for these two materials. More information on this federal program is available on the web page: *www.epa.gov/rmp*.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
Acid Rain Permit No. 2019-0785-ARR4 was issued on December 5, 2019. The permit contains the SO_2 allowances as published in § 73.10.

Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
This part provides for allocation, tracking, holding, and transferring of SO_2 allowances.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
The facility shall comply with the emission monitoring and reporting requirements of this Part. Certification testing has been completed for the CEM system required for each unit, and the EPA issued a certification for Wall Boiler Units 1 and 2 (B-02-1 and B-02-2) on February 3, 1997. Wall Boiler Unit 1 (B-02-1) was permanently decommissioned in December 2020.

Acid Rain, 40 CFR Part 76 (Phase II NOx requirements) [Applicable]
This part provides for NO_X emission limitations and reductions for coal-fired utility units only. NO_X requirements in accordance with regulations implementing Section 407 of the Clean Air Act are incorporated.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

The standard conditions of the permit address the requirements specified at § 82.156 for persons opening appliances for maintenance, service, repair, or disposal; § 82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; § 82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; § 82.166 for recordkeeping; § 82.158 for leak repair requirements; and § 82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

Federal NO_X and SO_2 Trading Programs, 40 CFR Part 97 [Subpart EEEEE is Applicable]
Subpart EEEEE, Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program. This subpart establishes various provisions for the CSAPR NO_X Ozone Season Group 2 Trading Program, under Section 110 of the Clean Air Act and under the Federal Implementation Plan (FIP) codified under 40 CFR § 52.38. Under this subpart, the permittee is required to designate an official representative, monitor emissions, keep records, and make reports in accordance with §§ 97.830 through 97.835. The monitoring program must comply with 40 CFR Part 75 or an alternative monitoring program must be requested and approved. CSAPR NO_X Ozone Season Group 2 allowances are periodically allocated to the facility and at the completion of the allowance transfer deadline for the control period in a given year the permittee is required to hold, in the source's compliance account administered by the EPA Clean Air Markets Division (CAMD), sufficient allowances available for deduction for such control period under § 97.824(a) in an amount not less than the tons of total NO_X emissions for the control period from all CSAPR NO_X

Ozone Season Group 2 units at the facility. The control period starts on May 1 of a calendar year, except as provided in § 97.806(c)(3), and ends on September 30 of the same year. For the CSAPR NO_X Ozone Season Group 2 Trading Program, the deadline for obtaining sufficient allowances is midnight of November 1 (if November 1 is a business day) or midnight of the first business day after November 1 (if November 1 is not a business day). Fines and future allowance deductions will be levied as described in § 97.806 if the permittee holds insufficient allowances at the completion of the allowance transfer deadline. The process of establishing an allowance account and requirements for administrating an account are included in § 97.820. The recording of allowance allocations is described in § 97.821. Submission and recording of allowance transfers is described in §§ 97.822 and 97.823. Compliance with ozone season emissions limitations and assurance provisions are described in §§ 97.824 and 97.825. Extra allowances may be banked (see § 97.826) and these vintage allowances may be used in later years with certain restrictions. These allowances do not constitute a property right. No Title V permit revision is required for any allocation, holding, deduction, or transfer of allowances in accordance with this subpart. Emission units B-02-2 and T-01-1 are CSAPR NO_X Ozone Season Group 2 units subject to the requirements of this subpart. The permit includes the requirement to comply with all applicable requirements of this subpart.

SECTION X. COMPLIANCE

Fees Paid

Major source construction modification permit fee of $5,000.

SECTION XI. TIER CLASSIFICATION, PUBLIC, AND EPA REVIEW

Tier Classification

This application has been classified as **Tier II** based on the request for a construction permit for a PSD major source. The applicant has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

Public Review

The applicant published a “Notice of Filing a Tier II Application” in the *The Paper* a weekly newspaper in Mayes County. The notice appeared in the newspaper on October 19, 2020. The notice stated that the application was available for public review at *The Paper* and at the Air Quality Division main office.

The applicant will be required to publish a “Notice of Tier II Draft Permit.” On publication of this notice, the 30-day public review period will start. The draft permit will also be available for public review on the Air Quality section of the DEQ web page at https://www.deq.ok.gov.

The requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process. Therefore, no additional opportunity to provide comments or EPA review, EPA objection, and petitions to EPA will be available to the public when requirements from the construction permit are incorporated into the Title V permit.

State Review

This facility is located within 50 miles of the Oklahoma border with the states of Arkansas and Missouri. The States of Arkansas and Missouri will be notified of the draft permit.

EPA Review

This permit has been approved for concurrent public and EPA review. If no comments are received from the public, the draft permit will be deemed the proposed permit. The draft/proposed permit will be submitted to EPA for a 45-day concurrent review. If comments are received from the public, a new proposed permit will be produced and the EPA review period will start over.

Public Petition

If the EPA does not object in writing during the 45-day review period, any person that meets the requirements of OAC 252:100-8-8 may petition the EPA within 60 days after the expiration of the 45-day review period to make such objection. Any such petition shall be based only on objections to the permit that the petitioner raised with reasonable specificity during the public comment period provided for in 27A O.S. § 2-14-302.A.2., unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objection arose after such period.

If the Administrator objects to the permit as a result of a petition filed under OAC 252:100-8-8(j) and the permit was issued after the end of the 45-day review period and prior to an EPA objection, that petition for review does not stay the effectiveness of the permit or its requirements. If the DEQ has issued a permit prior to receipt of an EPA objection under OAC 252:100-8-8(j), the DEQ will modify, terminate, or revoke such permit, and shall do so consistent with the procedures in 40 CFR §§ 70.7(g)(4) or (5)(i) and (ii), except in unusual circumstances. If the DEQ revokes the permit, it may thereafter issue only a revised permit that satisfies EPA's objection.

SECTION XII. SUMMARY

This facility has demonstrated the ability to comply with all Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues concerning this facility that would prevent issuance of this permit. Issuance of the amended construction permit is recommended, contingent on public and EPA review.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Grand River Dam Authority **Permit No.: 2014-1728-C (M-4) PSD**
Grand River Energy Center **Facility ID: 799**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on February 8, 2019, and all supplemental material. The Evaluation Memorandum dated June 15, 2021, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emissions limitations for each point. Particulate emissions, whether PM, PM_{10}, or $PM_{2.5}$, unless otherwise indicated, should be assumed to apply to State of Oklahoma standards, namely, total PM in that category, otherwise described as the sum of filterable and condensable or front-half and back-half. [OAC 252:100-8-6(a)]

EUG 1 and Insignificant Sources

No emission limitations are set except for those implicit in the definition of "Insignificant Activity." GRDA identified various pieces of equipment as fitting the Insignificant Activity definition including one 150,000 gallon above-ground No. 2 fuel storage tanks, a 10,000 gallon diesel fuel tank and dispensing equipment, a gasoline pump and storage tank, two 20,000 gallon tanks that act as separators for used lube oil, alkaline/phosphate washers, cold degreasing operations, welding, cutting, and soldering operations, water washing, sanitary sewage facilities, chemical, paint, and/or solvent storage room exhaust systems, spot cleaning with cans less than one liter capacity, and miscellaneous activities emitting less than 5 TPY (actual) of any criteria pollutant. Any Activity to which a State or federal applicable requirement applies is not an Insignificant Activity.

EUG 2

All equipment previously listed in EUG 2 has been permanently decommissioned from the facility.

EUG 3 Combustion Sources, Wall Boiler Unit 2

EU	Point	Make/National ID#	MW	MMBTU/hr
B-02	2	Foster-Wheeler #6905	520	5,296

Source EU/Point	Criteria Pollutants	Emissions	
		lb/hr	TPY
Wall Boiler Unit 2 B-02-2	PM/PM_{10} (a)	147	646
	VOC	18.4	80.7
	CO (b)	1,430	6,263

Source EU/Point	Criteria Pollutants	Emissions	
		lb/hr	TPY
Wall Boiler Unit 2 B-02-2	SO_2 (c)	3,177	-
	NOx	2,648	11,598

(a) PM emissions include filterable and condensable (“front-half” and “back-half”).
(b) CO emissions are also subject to a Best Available Control Technology limit, 30-calendar-day rolling average of 0.27 lb/MMBTU, utilizing Good Combustion Controls. Compliance shall be demonstrated as indicated in Specific Condition No. 23 (annual stack testing).
(c) Permit PSD-OK-552 (and 81-114-O) condition is 0.6 lb/MMBTU and 3,177 lb/hr, but no annual limit was established.

EUG 4 Combustion Sources, Auxiliary Boilers No. 1-3

Auxiliary Boilers No. 1 and 2 (B-02-3 and B-02-4) are limited to the emission equivalent of 2,760 hours of operation for each boiler at full load per 12-month period. Auxiliary Boiler No. 3 (B-02-5) is limited to the emissions equivalent limit of less than 876 hours per 12-month period at full load. The auxiliary boilers shall only combust natural gas. The emission equivalent hours of operation for each unit shall be calculated as a sum of the hours of operation multiplied by the ratio of the actual heat input for each hour of operation to the permitted heat input at full load as indicated below.

Emission Equivalent Hours of Operation

$$\sum_{i=1}^{N} 1\ Hr \left(\frac{Actual\ HI_i}{Permit\ HI}\right)$$

Where:
N = Operating hours per 12-month period
1 Hr = One hour of operation
Actual HI_i = Actual Heat Input at hour i
Permit HI_ = Permit Heat Input value at full load

EU	Point	Make/ National ID#	MW	MMBTU/hr
B-02	3	Zurn #18929	27	90
B-02	4	Zurn #18930	27	90
B-02	5	WTB # 13053	N/A	278

Source EU/Point	Criteria Pollutant	Emissions	
		lb/hr	TPY
Auxiliary Boiler No. 1 B-02-3	$PM/PM_{10}/PM_{2.5}$	1.22	1.68
	VOC	0.56	0.77
	CO	3.42	4.72
	SO_2	1.28	1.77
	NOx	3.42	4.72
Auxiliary Boiler No. 2 B-02-4	$PM/PM_{10}/PM_{2.5}$	1.22	1.68
	VOC	0.56	0.77
	CO	3.42	4.72

Source EU/Point	Criteria Pollutant	Emissions	
		lb/hr	TPY
Auxiliary Boiler No. 2 B-02-4	SO_2	1.28	1.77
	NOx	3.42	4.72
Auxiliary Boiler No. 3 B-02-5	$PM/PM_{10}/PM_{2.5}$	3.65	1.60
	VOC	1.67	0.73
	CO	10.26	4.49
	SO_2	3.86	1.69
	NOx	10.26	4.49

EUG 5 Coal Transfer, Conveying, Crushing

EU	Pt.	Process
TO-03	01	Dumper vibrating feeder to CV-1 [conveyor] to yard transfer tower
TO-03	02	Yard transfer tower to stacker/reclaimer CV-2
TO-03	03	Stacker/reclaimer CV-2 to belt conveyor trailer
TO-03	04	Belt conveyor trailer to stacker/reclaimer boom belt
TO-03	05	Stacker/reclaimer boom conveyor to active storage pile
TO-03	06	Transfer to stacker/reclaimer as reclaim from active storage pile
TO-03	07	Stacker/reclaimer bucket to stacker/reclaimer boom belt
TO-03	08	Stacker/reclaimer boom belt to CV-2 to transfer tower
TO-03	09	Yard belt CV-2 transfer to crusher building CV-4
TO-03	10	Conveyor CV-4 transfer to crusher surge bin
TO-03	11	Crusher surge bin transfer to crusher
TO-03	12	Crusher transfer to plant transfer CV-6A or CV-6B
TO-03	13	From CV-6A/6B at plant transfer bldg. to tripper gallery CV-7A/7B
TO-03	14	CV-7A or -7B transfer to coal silos via traveling trippers
TO-03	15	Yard transfer tower to emergency stacker belt CV-3
TO-03	16	Emergency stacker telescopic chute to emergency coal pile
TO-03	17	Transfer from reclaim equipment in emergency stockpile to emergency reclaim grizzly
TO-03	18	Emergency stock pile feeder to crusher house CV-5
TO-03	19	OK coal pile feeder to crusher house CV-8
TO-03	20	CV-8 to crusher tower
TO-03	21	Crusher tower transfer to crusher surge bin
TO-03	22	Crusher surge bin transfer to crusher jaws
TO-03	23	Crusher transfer to plant transfer tower CV-6A or CV-6B
TO-03	24	From CV-6A/6B at plant transfer tower to tripper gallery CV-7A/7B
TO-03	25	CV-7A or -7B to coal silo
TO-03	30	Mixer/crusher #1/2
TO-03	31	Mixer/crusher #1/2 to CV-6A/B
CU-03	01	Wyoming coal railcar unloading to hopper

Particulate Emissions

EU/Point	lb/hr	TPY
TO-03-01	3.12	2.80
TO-03-02	1.56	1.40
TO-03-03	13.10	16.64
TO-03-04	13.10	16.64
TO-03-05	3.74	4.75
TO-03-06	9.36	13.62
TO-03-07	13.10	19.06
TO-03-08	13.10	19.06
TO-03-09	1.66	2.72
TO-03-10	0.83	1.36
TO-03-11	0.83	1.36
TO-03-12	0.83	1.36
TO-03-13	0.83	1.36
TO-03-14	0.83	1.36

EU/Point	lb/hr	TPY
TO-03-15	1.17	0.21
TO-03-16	4.68	0.85
TO-03-17	N/A	0.21
TO-03-18	8.32	4.23
TO-03-19	0.15	0.01
TO-03-20	0.07	0.01
TO-03-21	0.07	0.01
TO-03-22	0.07	0.01
TO-03-23	0.07	0.01
TO-03-24	0.07	0.01
TO-03-25	0.07	0.01
TO-03-30	0.01	0.01
TO-03-31	0.01	0.01
CU-03-01	3.12	2.80

Note: PM_{10} = 47.3% of all PM and $PM_{2.5}$ = 7.2% of all PM for all points except TO-03-30 and TO-03-31, for which PM = PM_{10} = $PM_{2.5}$.

EUG 6 Materials Handling

EU	Point	Process
BL-06	01	Bottom ash loading (hopper to truck)
BU-06	01	Bottom ash unloading to hopper
FL-05	01	Fly ash loading (hopper to truck)
FU-05	01	Fly ash unloading to hopper
LU-04	01	Truck unloading (lime) to hopper
PAC-01	01	Bin vent - PAC Silo 1
PAC-02	02	Bin vent - PAC Silo 2

Particulate Emissions

EU/Point	Process	lb/hr	TPY
BL-06-01	Bottom ash loading (hopper to truck)	-0-	-0-
BU-06-01	Bottom ash unloading to hopper	-0-	-0-
FL-05-01	Fly ash loading (hopper to truck)	0.12	0.01
FU-05-01	Fly ash unloading to hopper	9.03	0.48
LU-04-01	Truck unloading (lime) to hopper	<0.01	<0.01
PAC-01	Bin vent - PAC Silo 1	0.05	0.20
PAC-02	Bin vent - PAC Silo 2	0.05	0.20

Note: PM_{10} = 47.3% of all PM and that $PM_{2.5}$ = 7.2% of all PM.

EUG 7 Truck & Maintenance Vehicle Traffic and Material Storage

EU	Pt.	Activity
CU-03	02	Truck unloading (OK coal) to yard
MV-03	01	Maintenance of inactive coal pile – unpaved road

EU	Pt.	Activity
MV-03	02	Reclaim coal from inactive storage to active storage – unpaved road
MV-03	03	Reclaim coal from emergency stockpile – unpaved road
MV-03	04	Reclaim coal from inactive coal pile to active coal pile – unpaved road
MV-03	05	Coal reclaim to grizzly – unpaved road
MV-03	06	Loaded OK coal truck delivery – unpaved road
MV-03	07	Empty OK coal truck delivery – unpaved road
MV-03	08	Maintenance and shaping of active storage pile – unpaved road
MV-05	01	Loaded fly ash truck traffic – ash disposal area – paved & unpaved roads
MV-05	02	Empty fly ash truck traffic – ash disposal area – paved & unpaved roads
MV-05	03	Maintenance of ash disposal area
MV-06	01	Loaded bottom ash truck traffic – ash disposal area – paved & unpaved roads
MV-06	02	Empty bottom ash truck traffic – ash disposal area – paved & unpaved roads
VT-03	01	Loaded OK coal truck delivery – paved road
VT-03	02	Empty OK coal truck delivery – paved road
VT-04	01	Loaded lime truck delivery – paved road
VT-04	02	Empty lime truck delivery – paved road
VT-05	01	Loaded fly ash truck delivery – paved road
VT-05	02	Empty fly ash truck delivery – paved road
VT-06	01	Loaded bottom ash truck delivery – paved & unpaved roads
VT-06	02	Empty bottom ash truck delivery – paved & unpaved roads
VT-09	01	Loaded PAC truck delivery – paved road
VT-09	02	Empty PAC truck delivery – paved road
VT-10	01	Loaded aqueous ammonia truck delivery – paved road
VT-10	02	Empty aqueous ammonia truck delivery – paved road
WE-03	01	Active Wyoming coal pile – wind
WE-03	02	Inactive Wyoming coal pile – wind
WE-03	03	Active Oklahoma coal pile – wind
WE-03	04	Emergency coal pile – wind
WE-08	01	Fly ash disposal area – wind

Note: Emissions from the activities and points listed in EUG 7 are fugitive emissions. No limits are set for these points or activities, but they are limited to the equipment, as it exists.

EUG 8 Combined Cycle Combustion Turbine Unit 3

The combined cycle combustion Turbine Unit 3 shall only combust natural gas.

EU	Point	Name & Make	Heat Capacity (MMBTUH)	Serial #
T-01	1	MHI 501J w/Duct Burner	4,160.9	A/141100

Source EU/Point	Pollutant	Emissions	
		lb/hr	TPY
Turbine Unit 3 T-01-1	$PM/PM_{10}/PM_{2.5}$	58.3	255
	VOC	16.6	73
	CO	133	583

Source EU/Point	Pollutant	Emissions	
		lb/hr	TPY
Turbine Unit 3 T-01-1	SO_2	62.4	273
	NO_X	250	1,094

EUG 9 Limited Use Engines

There are no limits on the emergency operations of these engines, but they are subject requirements under NSPS and NESHAP, per Specific Conditions No. 16 and 19.

[40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ]

EU	Point	Description	Hp	Serial #
EG-01	1	Emergency Generator Engine	1,190	59675
EG-02	2	Emergency Generator Engine	1,190	24Z00966
FP-03	1	Fire Pump Engine	390	10789853
EG-03	3	Emergency Generator Engine	2,922	33204737

2. Compliance with the authorized emission limits of Specific Condition No. 1 shall be demonstrated by adherence to the operating scenarios described as follows. The **Base Scenario** for Wall Boiler Unit 2 consists of operating on coal with occasional use of commercial grade natural gas for the main boiler igniters for flame stabilization. Wall Boiler Unit 2 is designed to use 90% Wyoming coal and 10% Oklahoma (bituminous) coal, with the ratio based on heating value. Wall Boiler Unit 2 may operate on 100% Wyoming coal. The **Alternative Scenario** for Wall Boiler Unit 2 consists of operating on “refined coal” with occasional use of commercial grade natural gas for the main boiler igniters for flame stabilization. Specific Condition No. 3 describes refined coal and establishes conditions for its use. The auxiliary boilers are designed to operate on natural gas, with igniters designed to operate on propane or natural gas. Sulfur dioxide emissions for distillate assume maximum sulfur content of $0.05\%_W$. [OAC 252:100-8-6(a)]

3. The permittee shall use coal, commercial grade natural gas, and/or diesel as required by the operating scenario under which it is operating. Commercial grade natural gas shall have a maximum sulfur content of 5 gr/100 SCF. Diesel shall have a maximum sulfur content of 0.05% by weight as prescribed in Specific Condition No. 2. Characteristics of the coal shall be compatible with emission control design but emission controls are necessary to meet the emissions limits.

[OAC 252:100-31]

4. The permittee shall be authorized to operate the facility continuously (24 hours per day, every day of the year) except as limited in the Specific Conditions. Operation of the following emissions units are limited as follows:

a. Auxiliary Boiler No. 1 — Emission equivalent of 2,760 hours of operation at full load per year based on a 12-month rolling total.

b. Auxiliary Boiler No. 2 — Emission equivalent of 2,760 hours of operation at full load per year based on a 12-month rolling total.

c. Auxiliary Boiler No. 3 — Emission equivalent of less than 876 hours at full load per year based on a 12-month rolling total.

d. Emergency Generators — 500 hours per year based on a 12-month rolling total.

e. Fire Pump Engine 500 hours per year based on a 12-month rolling total.
[OAC 252:100-8-6(a)]

5. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements including the following. [40 CFR Parts 72, 73, 75, & 76]

a. SO_2 allowances and NO_X limits as listed in Acid Rain permit.
b. Report quarterly emissions to EPA per 40 CFR Part 75.
c. Conduct RATA tests per 40 CFR Part 75.
d. QA/QC plan for maintenance of the CEMS.
e. NO_X emission reduction program requirements of 40 CFR Part 76.

6. Flue gas desulfurization (FGD) on Wall Boiler Unit 2 (B-02-2) shall be operated and maintained whenever the unit is operating. The FGD may be replaced by a device of equal or greater efficiency which can provide the 70% sulfur dioxide reduction (minimum) required by NSPS Subpart Da.
[40 CFR Part 60, Subpart Da]

7. Waste material generated by chemical cleaning of the boilers and/or Heat Recovery Steam Generator (HRSG) may be oxidized by injection into the furnaces.

8. Each engine and turbine at the facility shall have a readily accessible, permanent identification plate attached, which shows the make, model number, and serial number. [OAC 252:100-43]

9. The permittee shall maintain and operate, during periods when water is being sprayed for dust control, a secondary binding agent pump, located in the yard transfer tower. This pump shall apply binding agent to coal being discharged at either the telescoping chute or the stacker bucket wheel. This pump shall also apply binding agent to coal to be reclaimed from the active storage pile and when reclaiming coal from the emergency pile. This secondary pump shall be inspected on a daily basis. [OAC 252:100-29]

10. The opacity of any emission to the atmosphere from any coal processing and conveying equipment coal storage systems, and coal transfer and loading systems shall not exceed 20%. This standard does not apply to open storage piles. The standard does not apply during periods of start-up, shutdown, or malfunction (SSM). The standard found in OAC 252:100-25 does not exempt periods of SSM. [40 CFR § 60.252, OAC 252-100-25]

11. Wall Boiler Unit 2 (B-02-2) performance testing covering particulate emissions shall be performed in a timely fashion so that results may be presented with the next renewal application. Particulate testing shall cover PM_{10} and $PM_{2.5}$, and testing shall include both federal and state standards; that is, filterable and condensable, or "front-half" and "back-half." [OAC 252:100-43]

12. Wall Boiler Unit 2 (B-02-2) is subject to a PM standard of 0.028 lb/MMBTU. Wall Boiler Unit 2 (B-02-2) is subject to an opacity standard of 20%, based on 6-minute averages. Wall Boiler Unit 2 (B-02-2) has a pulse jet fabric filter (PJFF) system for control of PM. Wall Boiler Unit 2 (B-02-2) is subject to the federal compliance assurance monitoring (CAM) 40 CFR Part 64 requirements for the emission limit indicated above and shall comply with all provisions of CAM including but not limited to the following. [40 CFR § 64.1 et. seq.]

a. § 64.1 Definitions
b. § 64.2 Applicability
c. § 64.3 Monitoring design criteria
d. § 64.4 Submittal requirements
e. § 64.5 Deadlines for submittals
f. § 64.6 Approval of monitoring
g. § 64.7 Operation of approved monitoring
h. § 64.8 Quality improvement plan (QIP) requirements
i. § 64.9 Reporting and recordkeeping requirements
j. § 64.10 Savings provisions

The following is the CAM plan for the PJFF controlling PM emissions from Wall Boiler Unit 2:

k. Monitoring Approach:
   i) Continuous monitoring of PM emissions is accomplished by using opacity as a surrogate.
l. Selection of indicators:
   i) Short-term abrupt changes in opacity may not signify problems because of variability in COMS response; however, abrupt changes of larger magnitude, regardless of whether the indicator level is exceeded, may also indicate impending exceedances. Thus, a second indicator is added, consisting of any increase of 10% in opacity.
   ii) Inspections of the PJFF are conducted on a routine basis while the unit(s) are in service. Internal inspections of the PJFF are conducted, as needed, during appropriate unit outages.
m. Corrective Actions:
   Appropriate responses are based on the type of indicator.
   i) If opacity does not return to normal operating levels within one hour, and if the cause of the opacity increase is not known, further analysis of the unit and of auxiliary operating data will be undertaken for the purpose of determining the cause of the opacity increase. On-duty supervisory personnel shall determine the cause of the opacity increase and initiate immediate corrective actions. In the event that stack opacity exceeds the indicator opacity for three continuous hours, with unit load above 50% of capacity, plant personnel will initiate the following corrective actions as necessary to reduce stack opacity below the maximum indicator level. This three hour rule is designed to allow sufficient time to investigate the cause, as well as to check the opacity monitor for malfunction.
      (1) Any portion of the PJFF found to not be in proper operating condition shall be repaired as soon as practical, including expenditure of overtime labor as necessary to minimize the time and magnitude of the exceedance event.
      (2) Reduce megawatt load as necessary to reduce opacity below the indicator level. Notify the system dispatcher of the load curtailment if it appears necessary to eliminate the sustained stack opacity event.
      (3) Report all suspected exceedances in the quarterly excess emission report.
   ii) This response addresses the 10% step increase in opacity, and is identical to that for (i) described immediately preceding. If the indicator levels are not exceeded, responses (2) and (3) are not required.

n. In the event further stack testing is needed to refine this plan or to more completely establish emissions of particulate matter, full and complete compliance with EPA stack test methods for particulate emissions, including Reference Methods 5 and 5i, as appropriate, shall be used.
o. Quality Control:
   i) The COMS will be certified and operated in accordance with 40 CFR Part 60, Appendix B. Periodic opacity of visible emissions, as necessary, will be determined using EPA Method 9 (40 CFR 60, Appendix A).
   ii) QA/QC checks and maintenance on the COMS will be conducted in accordance with the plant's monitoring plan and manufacturer's recommendations.
p. Recordkeeping and Reporting:
   i) All opacity exceedances recorded by the COMS will be reported to the DEQ as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. All such opacity exceedances will be subsequently included with quarterly excess emissions reports, 6-month monitoring reports and annual compliance certifications. All such records will be maintained in accordance with 40 CFR 70.6(a)(3)(ii)(B), and 40 CFR Part 52, Subpart E, and will be maintained a minimum of five years. All records associated with the Corrective Actions discussed in Specific Condition No. 10 (m.) above will also be kept for a minimum of five years.
   ii) Records of all COMS QA/QC checks and any associated corrective actions will be kept for a minimum of five years.
   iii) Records of periodic PJFF pressure differential checks and any associated corrective actions will be kept for a minimum of five years.
   iv) Records of all PJFF inspections and any associated corrective actions will be kept for a minimum of five years.
   v) Results of all particulate matter emissions testing will be reported to the DEQ following testing and such records will be kept for a minimum of five years.

13. Wall Boiler Unit 2 (B-02-2) in EUG 3 is subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart Da, and shall comply with all provisions of the subpart including but not limited to the following. [40 CFR § 60.40Da et. seq.]

a. § 60.40Da Applicability and designation of affected facility.
b. § 60.41Da Definitions.
c. § 60.42Da Standard for particulate matter (PM).
d. § 60.43Da Standard for sulfur dioxide (SO_2).
e. § 60.44Da Standard for nitrogen oxides (NO_X).
f. § 60.45Da Alternative standards for combined nitrogen oxides (NO_X) and carbon monoxide (CO).
g. § 60.47Da Commercial demonstration permit.
h. § 60.48Da Compliance provisions.
i. § 60.49Da Emission monitoring.

j. § 60.50Da Compliance determination procedures and methods.
k. § 60.51Da Reporting requirements.
l. § 60.52Da Recordkeeping requirements.

14. Auxiliary Boiler No. 3 (B-02-05) in EUG 4 is subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart Db, and shall comply with all provisions of the subpart including but not limited to the following. [40 CFR § 60.40b et. seq.]

a. § 60.40b Applicability and delegation of authority.
b. § 60.41b Definitions.
c. § 60.44b Standard for nitrogen oxides (NOx).
d. § 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.
e. § 60.48b Emission monitoring for particulate matter and nitrogen oxides.
f. § 60.49b Reporting and Recordkeeping requirements

15. The coal processing equipment in EUG 5 and EUG 7 is subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart Y, and shall comply with all provisions of the subpart including but not limited to the following. [40 CFR § 60.250 et. seq.]

a. § 60.250 Applicability and designation of affected facility.
b. § 60.251 Definitions.
c. § 60.254 Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles.
d. § 60.255 Performance tests and other compliance requirements.
e. § 60.256 Continuous monitoring requirements.
f. § 60.257 Test methods and procedures.
g. § 60.258 Reporting and recordkeeping.
h. Only equipment or methods of equal or greater efficiency shall replace the following equipment or methods at the locations indicated.
   i) Partial enclosure and wet surfactant spray with binding agent – 90%
      TO-03-019 Oklahoma coal pile feeder to crusher house conveyor
      CU-03-001 Wyoming coal railcar unloading to hopper
   ii) Total enclosure and wet surfactant spray – 90%
      TO-03-001 Railcar dumper to yard transfer tower
   iii) Wet spray bars and reliance on occasional rain – 50%
      TO-03-006 Transfer to stacker/reclaimer from active storage
   iv) Total enclosure and capture by wet rotoclone – 95%
      TO-03-002 Yard transfer tower to stacker/reclaimer conveyor 2
      TO-03-009 Yard belt to crusher building conveyor
      TO-03-010 Conveyor 4 transfer to crusher surge bin
      TO-03-011 Crusher surge bin transfer to crusher
      TO-03-012 Crusher transfer to plant transfer conveyors 6A or 6B
      TO-03-013 Transfer from conveyors 6A or 6B to tripper gallery belt 7A or 7B
      TO-03-014 Conveyor 7A or 7B transfer to coal silos via traveling trippers
      TO-03-015 Yard transfer tower to emergency stacker belt 3
      TO-03-020 Conveyor 8 to crusher tower

TO-03-021 Crusher tower transfer to crusher surge bin
TO-03-022 Crusher surge bin 8 to crusher jaws
TO-03-023 Crusher transfer to plant transfer tower, 6A or 6B
TO-03-024 Conveyor 6A or 6B at plant transfer tower to tripper gallery 7A or 7B
TO-03-025 Conveyor 7A or 7B to coal silo
TO-03-030 Mixer/crusher #1/2
TO-03-031 Mixer/crusher #1/2 to CV-6A/B

v) Wet spray bar on bucket wheel with binding agent – 80%
TO-03-005 Stacker/reclaimer boom conveyor to active storage pile

vi) Telescoping chute with dust control binding agent – 80%
TO-03-016 Emergency stacker telescopic chute to emergency coal pile

vii) Wet coal (from previous spraying) – 30%
TO-03-003 Stacker/reclaimer conveyor 2 to belt conveyor trailer
TO-03-004 Belt conveyor trailer to stacker/reclaimer boom belt
TO-03-007 Stacker/reclaimer bucket to stacker/reclaimer boom belt
TO-03-008 Stacker/reclaimer boom belt to yard belt conveyor 2 to transfer tower

viii) Total enclosure and evacuation to baghouse – 99%
FL-05-001 Fly ash loading hopper to truck
FL-04-001 Lime unloading truck to hopper

ix) Watering
WE-08-001 Fly Ash disposal area-wind
VT-04-001 Loaded lime truck delivery
VT-04-002 Empty lime truck delivery

x) Dust control binding agent
CU-03-002 Truck unloading (OK coal) to yard
MV-03-001 Maintenance of inactive coal pile
MV-03-002 Reclaim coal from inactive storage to active storage
MV-03-003 Reclaim coal from emergency stockpile
MV-03-004 Reclaim coal from inactive coal pile to active coal pile
MV-03-005 Coal reclaim to grizzly
MV-03-006 Loaded bituminous coal truck traffic
MV-03-007 Empty bituminous coal truck traffic
MV-03-008 Maintenance and shaping of active storage pile
VT-03-001 Loaded OK coal truck delivery
VT-03-002 Empty OK coal truck delivery

xi) Watering or dust control binding agent, as necessary
MV-05-001 Loaded fly ash truck traffic – ash disposal area
MV-05-002 Empty fly ash truck traffic – ash disposal area
MV-05-003 Maintenance of ash disposal area
MV-06-001 Loaded bottom ash truck traffic – ash disposal area
MV-06-002 Empty bottom ash truck traffic – ash disposal area
VT-05-001 Loaded fly ash truck delivery – paved road
VT-05-002 Empty fly ash truck delivery – paved road
VT-06-001 Loaded bottom ash truck delivery – paved road
VT-06-002 Empty bottom ash truck delivery – paved road

16. The engine for Emergency Generator (EG-03-3) in EUG 9 is subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart IIII, and shall comply with all provisions of the subpart including but not limited to: [40 CFR § 60.4200 et. seq.]

a. § 60.4200 Am I subject to this subpart?
b. § 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?
c. § 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?
d. § 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
e. § 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?
f. § 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?
g. § 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?
h. § 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
i. § 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
j. § 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?
k. § 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?
l. § 60.4214 Notification, reporting, and recordkeeping requirements
m. § 60.4218 What parts of the General Provisions apply to me?
n. § 60.4219 What definitions apply to this subpart?

17. The combined cycle combustion Turbine Unit 3 and associated duct burner (T-01-1) in EUG 8 subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart KKKK, and shall comply with all provisions of the subpart including but not limited to the following.
[40 CFR § 60.4300 et. seq.]

a. § 60.4300 What is the purpose of this subpart?
b. § 60.4305 Does this subpart apply to my stationary combustion turbine?
c. § 60.4310 What types of operations are exempt from these standards of performance?
d. § 60.4315 What pollutants are regulated by this subpart?
e. § 60.4320 What emission limits must I meet for nitrogen oxides (NO_X)?
f. § 60.4325 What emission limits must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?
g. § 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?
h. § 60.4333 What are my general requirements for complying with this subpart?
i. § 60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?

j. § 60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?
k. § 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?
l. § 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?
m. § 60.4355 How do I establish and document a proper parameter monitoring plan?
n. § 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?
o. § 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?
p. § 60.4370 How often must I determine the sulfur content of the fuel?
q. § 60.4375 What reports must I submit?
r. § 60.4380 How are excess emissions and monitor downtime defined for NO_X?
s. § 60.4385 How are excess emissions and monitoring downtime defined for SO_2?
t. § 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?
u. § 60.4395 When must I submit my reports?
v. § 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?
w. § 60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?
x. § 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
y. § 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?
z. § 60.4420 What definitions apply to this subpart?

18. The combined cycle combustion Turbine Unit 3 (T-01-1) in EUG 8 is subject to federal National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63, Subpart YYYY, and shall comply with all provisions of the subpart including but not limited to the following. [40 CFR § 63.6080 *et. seq.*]

a. § 63.6080 What is the purpose of subpart YYYY?
b. § 63.6085 Am I subject to this subpart?
c. § 63.6090 What parts of my plant does this subpart cover?
d. § 63.6092 Are duct burners and waste heat recovery units covered by subpart YYYY?
e. § 63.6095 When do I have to comply with this subpart?
f. § 63.6100 What emission and operating limitations must I meet?
g. § 63.6105 What are my general requirements for complying with this subpart?
h. § 63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?
i. § 63.6115 When must I conduct subsequent performance tests?
j. § 63.6120 What performance tests and other procedures must I use?
k. § 63.6125 What are my monitor installation, operation, and maintenance requirements?
l. § 63.6130 How do I demonstrate initial compliance with the emission and operating limitations?
m. § 63.6135 How do I monitor and collect data to demonstrate continuous compliance?
n. §63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?
o. § 63.6145 What notifications must I submit and when?

p. § 63.6150 What reports must I submit and when?
q. § 63.6155 What records must I keep?
r. § 63.6160 In what form and how long must I keep my records?
s. § 63.6165 What parts of the General Provisions apply to me?
t. § 63.6170 Who implements and enforces this subpart?
u. § 63.6175 What definitions apply to this subpart?

19. The Emergency Generator Engines (EG-01-1, EG-02-2, & EG-03-3) and Fire Pump Engine (FP-03-1) in EUG 9 are subject to federal National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63, Subpart ZZZZ, and shall comply with all applicable requirements of this subpart, including but not limited to the following. [40 CFR § 63.6580 et. seq.]

a. § 63.6580 What is the purpose of subpart ZZZZ?
b. § 63.6585 Am I subject to this subpart?
c. § 63.6590 What parts of my plant does this subpart cover?
d. § 63.6595 When do I have to comply with this subpart?
e. § 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?
f. § 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?
g. § 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?
h. § 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?
i. § 63.6605 What are my general requirements for complying with this subpart?
j. § 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?
k. § 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?
l. § 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?
m. § 63.6615 When must I conduct subsequent performance tests?
n. § 63.6620 What performance tests and other procedures must I use?
o. § 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?
p. § 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?
q. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

r. § 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?
s. § 63.6645 What notifications must I submit and when?
t. § 63.6650 What reports must I submit and when?
u. § 63.6655 What records must I keep?
v. § 63.6660 In what form and how long must I keep my records?
w. § 63.6665 What parts of the General Provisions apply to me?
x. § 63.6670 Who implements and enforces this subpart?
y. § 63.6675 What definitions apply to this subpart?

20. Auxiliary Boilers No. 1, 2, and 3 (B-02-3, B-02-4, & B-02-5) are subject to federal National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63, Subpart DDDDD, and shall comply with all provisions of the subpart including but not limited to the following.
[40 CFR §63.7480 et. Seq.]

a. § 63.7480 What is the purpose of this subpart?
b. § 63.7485 Am I subject to this subpart?
c. § 63.7490 What is the affected source of this subpart?
d. § 63.7491 Are any boilers or process heaters not subject to this subpart?
e. § 63.7495 When do I have to comply with this subpart?
f. § 63.7499 What are the subcategories of boilers and process heaters?
g. § 63.7500 What emission limitations, work practice standards, and operating limits must I meet?
h. § 63.7505 What are my general requirements for complying with this subpart?
i. § 63.7510 What are my initial compliance requirements and by what date must I conduct them?
j. § 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?
k. § 63.7520 What stack tests and procedures must I use?
l. § 63.7521 What fuel analyses, fuel specification, and procedures must I use?
m. § 63.7522 Can I use emissions averaging to comply with this subpart?
n. § 63.7525 What are my monitoring, installation, operation, and maintenance requirements?
o. § 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?
p. § 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?
q. § 63.7535 Is there a minimum amount of monitoring data I must obtain?
r. § 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?
s. § 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?
t. § 63.7545 What notifications must I submit and when?
u. § 63.7550 What reports must I submit and when?
v. § 63.7555 What records must I keep?
w. § 63.7560 In what form and how long must I keep my records?
x. § 63.7565 What parts of the General Provisions apply to me?
y. § 63.7570 Who implements and enforces this subpart?

z. § 63.7575 What definitions apply to this subpart?

21. Wall Boiler Unit 2 (B-02-2) in EUG 3 is subject to federal National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63, Subpart UUUUU, and shall comply with all provisions of the subpart including but not limited to the following.

[40 CFR § 63.9980 et. seq.]

a. § 63.9980 What is the purpose of this subpart?
b. § 63.9981 Am I subject to this subpart?
c. § 63.9982 What is the affected source of this subpart?
d. § 63.9983 Are any EGUs not subject to this subpart?
e. § 63.9984 When do I have to comply with this subpart?
f. § 63.9985 What is a new EGU?
g. § 63.9990 What are the subcategories of EGUs?
h. § 63.9991 What emission limitations, work practice standards, and operating limits must I meet?
i. § 63.10000 What are my general requirements for complying with this subpart?
j. § 63.10001 Affirmative defense for exceedance of emission limit during malfunction.
k. § 63.10005 What are my initial compliance requirements and by what date must I conduct them?
l. § 63.10006 When must I conduct subsequent performance tests or tune-ups?
m. § 63.10007 What methods and other procedures must I use for the performance tests?
n. § 63.10009 May I use emissions averaging to comply with this subpart?
o. § 63.10010 What are my monitoring, installation, operation, and maintenance requirements?
p. § 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?
q. § 63.10020 How do I monitor and collect data to demonstrate continuous compliance?
r. § 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?
s. § 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?
t. § 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?
u. § 63.10030 What notifications must I submit and when?
v. § 63.10031 What reports must I submit and when?
w. § 63.10032 What records must I keep?
x. § 63.10033 In what form and how long must I keep my records?
y. § 63.10040 What parts of the General Provisions apply to me?
z. § 63.10041 Who implements and enforces this subpart?
aa. § 63.10042 What definitions apply to this subpart?

22. Wall Boiler Unit 2 (B-02-2) in EUG 3, and Turbine Unit 3 (T-01-1) in EUG 8 are subject to the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program 40 CFR Part 97, Subpart EEEEE. The permittee shall comply with all applicable requirements including but not limited to: [40 CFR § 97.801 to § 97.835]

a. § 97.801 Purpose.
b. § 97.802 Definitions.
c. § 97.803 Measurements, abbreviations, and acronyms.
d. § 97.804 Applicability.
e. § 97.805 Retired unit exemption.
f. § 97.806 Standard requirements.
g. § 97.807 Computation of time.
h. § 97.808 Administrative appeal procedures.
i. § 97.810 State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.
j. § 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.
k. § 97.812 CSAPR NO_X Ozone Season Group 2 allowance allocations to new units.
l. § 97.813 Authorization of designated representative and alternate designated representative.
m. § 97.814 Responsibilities of designated representative and alternate designated representative.
n. § 97.815 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.
o. § 97.816 Certificate of representation.
p. § 97.817 Objections concerning designated representative and alternate designated representative.
q. § 97.818 Delegation by designated representative and alternate designated representative.
r. § 97.820 Establishment of compliance accounts, assurance accounts, and general accounts.
s. § 97.821 Recordation of CSAPR NO_X Ozone Season Group 2 allowance allocations and auction results.
t. § 97.822 Submission of CSAPR NO_X Ozone Season Group 2 allowance transfers.
u. § 97.823 Recordation of CSAPR NO_X Ozone Season Group 2 allowance transfers.
v. § 97.824 Compliance with CSAPR NO_X Ozone Season Group 2 emissions limitation.
w. § 97.825 Compliance with CSAPR NO_X Ozone Season Group 2 assurance provisions.
x. § 97.826 Banking.
y. § 97.827 Account error.
z. § 97.828 Administrator's action on submissions.
aa. § 97.830 General monitoring, recordkeeping, and reporting requirements.
bb. § 97.831 Initial monitoring system certification and recertification procedures.
cc. § 97.832 Monitoring system out-of-control periods.
dd. § 97.833 Notifications concerning monitoring.
ee. § 97.834 Recordkeeping and reporting.
ff. § 97.835 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

23. The permittee shall conduct the following testing as indicated below when operating under representative conditions. Testing shall be conducted using the approved reference methods listed below. [OAC 252:100-8-6 (a)(3)(A) & OAC 252:100-43]

a. Periodic testing of the listed emissions units for the specified pollutant shall be conducted at least once during the specified frequency starting from the issuance date of this permit:

Periodic Testing Schedule

EU/Point	Pollutant	Frequency
B-02-2	CO	1 Year
T-01-1	CO	1 Year

b. The following reference methods specified in 40 CFR 60 shall be used:
  i) Method 1: Sample and Velocity Traverses for Stationary Sources.
  ii) Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
  iii) Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
  iv) Method 4: Determination of Moisture in Stack Gases.
  v) Method 10: Determination of Carbon Monoxide Emissions from Stationary Sources.

c. Performance testing shall be conducted while the units are operating under representative conditions within 10% of maximum production rate.

d. A protocol describing the testing plan shall be submitted to the Air Quality Division at least 30 days prior to the testing.

e. A written report documenting the results of emissions testing shall be submitted within 60 days of completion of on-site testing.

24. The following records shall be maintained on-site. All such records shall be made available to regulatory personnel upon request. These records shall be maintained for a period of at least five years after the time they are made. [OAC 252:100-43]

a. Total usage of each type of fuel, including each of Wyoming and Oklahoma coal for Wall Boiler Unit 2, natural gas for each auxiliary boiler, and natural gas for Wall Boiler Unit 2 igniter, and all other materials burned or disposed of in the boiler (monthly and cumulative annual).

b. Material handling throughputs (annual).

c. Commercial grade natural gas fuel sulfur content as required by Specific Condition No. 3. This condition may be satisfied using a current gas company bill or other approved method and shall be demonstrated at least once every calendar year.

c. Sulfur content of diesel fuel as required by Specific Condition No. 3. This condition may be satisfied by maintaining a vendor’s statement that the fuel complies with the facility’s $0.05\%_W$ sulfur specification.

d. Records and emissions as required by the Acid Rain Program.

e. RATA test results from periodic CEMS certification tests.

f. Operating hours for Wall Boiler Unit 2 and for Auxiliary Boilers No. 1, 2, and 3.

g. Operating hours for Emergency Generator Engines and Fire Pump Engine.

h. PJFF inspection reports, per Specific Condition No. 12.

i. All records required by CAM per Specific Condition No. 12.

j. Records necessary to demonstrate compliance with OAC 252:100-8-36.2(c)(1) & (3).

k. Records demonstrating compliance with the following NSPS subparts:
  Subpart Da, per Specific Conditions No. 6 and 13;
  Subpart Db, per Specific Condition No. 14;
  Subpart Y, per Specific Conditions No. 10 and 15;

Subpart IIII, per Specific Condition No. 16; and
Subpart KKKK, per Specific Condition No. 17.

l. Periodic Testing as required by Specific Condition No. 23.
m. Records demonstrating compliance with the following NESHAP subparts:
Subpart YYYY, per Specific Condition No. 18;
Subpart ZZZZ, per Specific Condition No. 19;
Subpart DDDDD, per Specific Condition No. 20; and
Subpart UUUUU, per Specific Condition No. 21.
n. Records demonstrating compliance with CSAPR Subpart EEEEE.
o. Records of binding agent usage and binding agent pump inspection records per Specific Condition No. 23.
p. $PM_{10}/PM_{2.5}$ testing per Specific Condition No. 11 and CO testing per Specific Condition No. 23.

25. The following records shall be maintained on-site to verify insignificant activities. No record keeping is required for Trivial Activities. [OAC 252:100-43]

a. Throughput for fuel storage/dispensing equipment operated solely for facility owned vehicles (total annual if throughput is less than 2,175 gallons per day).
b. Capacity of all storage tanks with a capacity of 39,894 gallons or less storing a fluid with a true vapor pressure less than 1.5 psia, and for each delivery of fluid, the type and quantity.
c. Quantity used of each coating, thinner, clean-up and degreasing solvent (total annual).

26. The permittee shall submit annually to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, certification of compliance with the terms and conditions of this permit.
[OAC 252:100-8-6 (c)(5)(A) & (D)]

a. No later than 30 days after each anniversary date of the original Part 70 permit (December 17, 1998),
b. Alternatively, the facility may submit an additional compliance report covering the period of December 17 to December 31, and thereafter submit certifications of compliance for the period of January 1 to December 31. All reports are due 30 days following the period which is covered by the report.

27. This facility is considered a Prevention of Significant Deterioration (PSD) facility. As such, the facility is subject to the provisions of OAC 252:100-8-36.2(c) for any projects as defined therein. [OAC 252:100-8-36.2 (c)]

28. This permit supersedes and replaces Construction Permits No. 2009-179-C (M-2) PSD, 2009-179-C (M-3), 2009-179-C (M-4), and 2009-179-C (M-5).

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(June 21, 2016)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(17) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;

(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

    (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
    (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
    (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
    (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]
(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]
(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must

keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).
(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 C.F.R. § 70.8(d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).
(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [OAC 252:100-43-6]

Department of Environmental Quality (DEQ)
Air Quality Division (AQD)
Acronym List
4-15-21

ACFM	Actual Cubic Feet per Minute
AD	Applicability Determination
AFRC	Air-to-Fuel Ratio Controller
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BAE	Baseline Actual Emissions
BHP	Brake Horsepower (bhp)
BTU	British thermal unit (Btu)
C&E	Compliance and Enforcement
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CAS	Chemical Abstract Service
CAAA	Clean Air Act Amendments
CC	Catalytic Converter
CCR	Continuous Catalyst Regeneration
CD	Consent Decree
CEM	Continuous Emission Monitor
CFC	Chlorofluorocarbon
CFR	Code of Federal Regulations
CI	Compression Ignition
CNG	Compressed Natural Gas
CO	Carbon Monoxide or Consent Order
COA	Capable of Accommodating
COM	Continuous Opacity Monitor
D	Day
DEF	Diesel Exhaust Fluid
DG	Demand Growth
DSCF	Dry Standard (At Standard Conditions) Cubic Foot (Feet)
EGU	Electric Generating Unit
EI	Emissions Inventory
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
EUG	Emissions Unit Group
EUSGU	Electric Utility Steam Generating Unit
FCE	Full Compliance Evaluation
FCCU	Fluid Catalytic Cracking Unit
FIP	Federal Implementation Plan
FR	Federal Register
GACT	Generally Achievable Control Technology
GAL	Gallon (gal)
GDF	Gasoline Dispensing Facility
GEP	Good Engineering Practice
GHG	Greenhouse Gases
GR	Grain(s) (gr)
H_2CO	Formaldehyde
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutants
HC	Hydrocarbon
HCFC	Hydrochlorofluorocarbon
HFR	Horizontal Fixed Roof
HON	Hazardous Organic NESHAP
HP	Horsepower (hp)
HR	Hour (hr)
I&M	Inspection and Maintenance
IBR	Incorporation by Reference
ICE	Internal Combustion Engine
LAER	Lowest Achievable Emission Rate
LB	Pound(s) [Mass] (lb, lbs, lbm)
LB/HR	Pound(s) per Hour (lb/hr)
LDAR	Leak Detection and Repair
LNG	Liquefied Natural Gas
LT	Long Ton(s) (metric)
M	Thousand (Roman Numeral)
MAAC	Maximum Acceptable Ambient Concentration
MACT	Maximum Achievable Control Technology
MM	Prefix used for Million (Thousand-Thousand)
MMBTU	Million British Thermal Units (MMBtu)
MMBTUH	Million British Thermal Units per Hour (MMBtu/hr)
MMSCF	Million Standard Cubic Feet (MMscf)
MMSCFD	Million Standard Cubic Feet per Day
MSDS	Material Safety Data Sheet
MWC	Municipal Waste Combustor
MWe	Megawatt Electrical
NA	Nonattainment
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NMHC	Non-methane Hydrocarbon
NGL	Natural Gas Liquids
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxides
NOI	Notice of Intent
NSCR	Non-Selective Catalytic Reduction

NSPS	New Source Performance Standards
NSR	New Source Review
O_3	Ozone
O&G	Oil and Gas
O&M	Operation and Maintenance
O&NG	Oil and Natural Gas
OAC	Oklahoma Administrative Code
OC	Oxidation Catalyst
PAH	Polycyclic Aromatic Hydrocarbons
PAE	Projected Actual Emissions
PAL	Plant-wide Applicability Limit
Pb	Lead
PBR	Permit by Rule
PCB	Polychlorinated Biphenyls
PCE	Partial Compliance Evaluation
PEA	Portable Emissions Analyzer
PFAS	Per- and Polyfluoroalkyl Substance
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter with an Aerodynamic Diameter <= 2.5 Micrometers
PM_{10}	Particulate Matter with an Aerodynamic Diameter <= 10 Micrometers
POM	Particulate Organic Matter or Polycyclic Organic Matter
ppb	Parts per Billion
ppm	Parts per Million
ppmv	Parts per Million Volume
ppmvd	Parts per Million Dry Volume
PSD	Prevention of Significant Deterioration
psi	Pounds per Square Inch
psia	Pounds per Square Inch Absolute
psig	Pounds per Square Inch Gage
RACT	Reasonably Available Control Technology
RATA	Relative Accuracy Test Audit
RAP	Regulated Air Pollutant or Reclaimed Asphalt Pavement
RFG	Refinery Fuel Gas
RICE	Reciprocating Internal Combustion Engine
RO	Responsible Official
ROAT	Regional Office at Tulsa
RVP	Reid Vapor Pressure
SCC	Source Classification Code
SCF	Standard Cubic Foot
SCFD	Standard Cubic Feet per Day
SCFM	Standard Cubic Feet per Minute
SCR	Selective Catalytic Reduction
SER	Significant Emission Rate
SI	Spark Ignition
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SOx	Sulfur Oxides
SOP	Standard Operating Procedure
SRU	Sulfur Recovery Unit
T	Tons
TAC	Toxic Air Contaminant
THC	Total Hydrocarbons
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulates
TV	Title V of the Federal Clean Air Act
$\mu g/m^3$	Micrograms per Cubic Meter
US EPA	U. S. Environmental Protection Agency
VFR	Vertical Fixed Roof
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compound
VOL	Volatile Organic Liquid
VRT	Vapor Recovery Tower
VRU	Vapor Recovery Unit
YR	Year
2SLB	2-Stroke Lean Burn
4SLB	4-Stroke Lean Burn
4SRB	4-Stroke Rich Burn

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON STREET, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit Number: 2014-1728-C (M-4) PSD

Grand River Dam Authority,

having complied with the requirements of the law, is hereby granted permission to construct modifications at the Grand River Energy Center in Sections 20, 21, 28 & 29, T20N, R19E, Chouteau, Mayes County, OK, subject to standard conditions dated June 21, 2016, and Specific Conditions, both attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date below, except as authorized under Section VIII of the Standard Conditions.

DRAFT

Division Director, Air Quality Division	**Date**

NOTICE OF DRAFT PERMIT

TIER II or TIER III AIR QUALITY PERMIT APPLICATION

APPLICANT RESPONSIBILITIES

Permit applicants are required to give public notice that a Tier II or Tier III draft permit has been prepared by DEQ. The notice must be published in one newspaper local to the site or facility. Upon publication, a signed affidavit of publication must be obtained from the newspaper and sent to AQD. Note that if either the applicant or the public requests a public meeting, this must be arranged through the Customer Services Division of the DEQ.

REQUIRED CONTENT (27A O.S. § 2-14-302 and OAC 252:4-7-13(c))

1. **A statement that a Tier II or Tier III draft permit has been prepared by DEQ;**
2. **Name and address of the applicant;**
3. **Name, address, driving directions, legal description and county of the site or facility;**
4. **The type of permit or permit action being sought;**
5. **A description of activities to be regulated, including an estimate of emissions from the facility;**
6. **Location(s) where the application and draft permit may be reviewed (a location in the county where the site/facility is located must be included);**
7. **Name, address, and telephone number of the applicant and DEQ contacts;**
8. **Any additional information required by DEQ rules or deemed relevant by applicant;**
9. **A 30-day opportunity to request a formal public meeting on the draft permit.**

SAMPLE NOTICE on page 2.

SAMPLE NOTICE ***(Italicized print is to be filled in by the applicant.)*****:**

DEQ NOTICE OF TIER …*II or III*… DRAFT PERMIT

A Tier …*II or III*… application for an air quality …*type of permit or permit action being sought (e.g., Construction Permit for a Major Facility)*… has been filed with the Oklahoma Department of Environmental Quality (DEQ) by applicant, …*name and address.*

The applicant requests approval to …*brief description of purpose of application*… at the …*site/facility name* … …[proposed to be] located at …*physical address (if any), driving directions, and legal description including county*…..

In response to the application, DEQ has prepared a draft permit [modification] (Permit Number: …*xx-xxx-x*…), which may be reviewed at …*locations (one must be in the county where the site/facility is located)*… or at the Air Quality Division's main office (see address below). The draft permit is also available for review in the Air Quality Section of DEQ's Web Page: http://www.deq.ok.gov/

This draft permit would authorize the facility to emit the following regulated pollutants: ***(list each pollutant and amounts in tons per year (TPY))***

The public comment period ends 30 days after the date of publication of this notice. Any person may submit written comments concerning the draft permit to the Air Quality Division contact listed below. [Modifications only, add: Only those issues relevant to the proposed modification(s) are open for comment.] A public meeting on the draft permit [modification] may also be requested in writing at the same address. Note that all public meetings are to be arranged and conducted by DEQ/CSD staff.

In addition to the public comment opportunity offered under this notice, this draft permit is subject to U.S. Environmental Protection Agency (EPA) review, EPA objection, and

petition to EPA, as provided by 40 CFR § 70.8. [For Construction Permits, add: The requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process. Therefore, no additional opportunity to provide comments or EPA review, EPA objection, and petitions to EPA will be available to the public when requirements from the construction permit are incorporated into the Title V permit.]

If the Administrator (EPA) does not object to the proposed permit, the public has 60 days following the Administrator's 45 day review period to petition the Administrator to make such an objection as provided in 40 CFR 70.8(d) and in OAC 252:100-8-8(j). Information on all permit actions and applicable review time lines is available in the Air Quality section of the DEQ Web page: http://www.deq.ok.gov/.

For additional information, contact …*names, addresses and telephone numbers of contact persons for the applicant,* or contact DEQ at: Chief Engineer, Permits & Engineering Group, Air Quality Division, 707 N. Robinson, Suite 4100, P.O. Box 1677, Oklahoma City, OK, 73101-1677. Phone No. (405) 702-4100.

DRAFT/PROPOSED

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

Robert Ladd
VP of Generation Operations
Grand River Dam Authority
P.O. Box 609
Chouteau, OK 74337

SUBJECT: Permit No. **2014-1728-C (M-4) PSD**
Grand River Dam Energy Center (Facility ID: 799)
Location: Sections 20, 21, 28 & 29, Township 20N, Range 19E
Mayes County, Oklahoma

Dear Mr. Ladd:

Enclosed is the permit authorizing a modification to their Prevention of Significant Deterioration (PSD) construction permit at the referenced facility. Please note that this permit is issued subject to the standard and specific conditions, which are attached.

Also note that you are required to submit an emissions inventory for this facility. An emissions inventory must be completed through DEQ's electronic reporting system by April 1st of the following calendar year in which the facility is registered. The reporting schedule thereafter is explained in OAC 252:100-5-2.1.(a)(2). Any questions concerning the reporting schedule or submittal process should be referred to the Emissions Inventory Staff at (405) 702-4100.

Thank you for your cooperation in this matter. If we may be of further service, please contact the permit writer at Anne.Smith@deq.ok.gov or (405) 702-4100.

Sincerely,

Anne Smith, P.E.
New Source Permits Section
AIR QUALITY DIVISION

Enclosures

Robert Ladd
VP of Generation Operations
Grand River Dam Authority
P.O. Box 609
Chouteau, OK 74337

SUBJECT: Permit No. **2014-1728-C (M-4) PSD**
Grand River Dam Energy Center (Facility ID: 799)
Location: Sections 20, 21, 28 & 29, Township 20N, Range 19E
Mayes County, Oklahoma

Dear Mr. Ladd:

Air Quality has completed initial review of the permit application for the referenced facility and completed a draft permit for public review. This application has been determined to be a Tier II application. In accordance with 27A O.S. 2-14-302 and OAC 252:4-7-13(c) the enclosed draft permit is ready for public review. The requirements for public review of the draft permit include the following steps, which you must accomplish:

1. Publish at least one legal notice (one day) in at least one newspaper of general circulation within the county where the facility is located. (Instructions enclosed)
2. Provide for public review (for a period of 30 days following the date of the newspaper announcement) a copy of the application and draft permit at a convenient location (preferentially at a public location) within the county of the facility.
3. Send AQD a written affidavit of publication for the notices from Item #1 above together with any additional comments or requested changes which you may have on the draft permit.

The permit review time is hereby tolled pending the receipt of the affidavit of publication. Please submit the requested information as soon as possible. You should be aware that failure to submit an adequate response within 180 days may result in the withdrawal of your application and forfeiture of your application fees. Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me or Anne Smith, the permit writer, at (405) 702-4100.

Sincerely,

Phillip Fielder

Phillip Fielder, P.E., Chief Engineer
AIR QUALITY DIVISION

Enclosures

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

Arkansas Dept. of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

SUBJECT: Permit No. **2014-1728-C (M-4) PSD**
Grand River Dam Energy Center (Facility ID: 799)
Location: Sections 20, 21, 28 & 29, Township 20N, Range 19E
Mayes County, Oklahoma
Permit Writer: Anne Smith, P.E.

Dear Sir / Madam:

The owner/operator of the above-referenced facility has applied for a modification to their Prevention of Significant Deterioration (PSD) construction permit. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Since this facility is within 50 miles of the Oklahoma - Arkansas border, a copy of the proposed permit will be provided to you upon request. Information on all permit actions and a copy of this draft permit are available for review by the public in the Air Quality Section of DEQ Web Page: *https://www.deq.ok.gov*.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me or the permit writer at (405) 702-4100.

Sincerely,

Phillip Fielder

Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

Missouri Department of Natural Resources
Air Pollution Control Program
Construction Permits
P. O. Box 176
Jefferson City, MO 65102-1076

SUBJECT: Permit No. **2014-1728-C (M-4) PSD**
Grand River Dam Energy Center (Facility ID: 799)
Location: Sections 20, 21, 28 & 29, Township 20N, Range 19E
Mayes County, Oklahoma
Permit Writer: Anne Smith. P.E.

Dear Sir / Madam:

The owner/operator of the above-referenced facility has applied to renew the facility's Title V operating permit under 40 CFR Part 70. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Since this facility is within 50 miles of the Oklahoma - Missouri border, a copy of the proposed permit will be provided to you upon request. Information on all permit actions and a copy of this draft permit are available for review by the public in the Air Quality Section of DEQ Web Page: *https://www.deq.ok.gov*.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me or the permit writer at (405) 702-4100.

Sincerely,

Phillip Fielder

Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION