OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **January 22, 2013**

TO: Phillip Fielder, P.E., Permits & Engineering Group Manager

THROUGH: Kendal Stegmann, Senior Environmental Manager, Compliance and Enforcement

THROUGH: Phil Martin, P.E., Manager, Existing Source Permits Section

THROUGH: Peer Review

FROM: David Schutz, P.E., New Source Permits Section

SUBJECT: Evaluation of Permit Application No. **2005-271-C (M-5)(PSD)**
Oklahoma Gas & Electric Company
Muskogee Generating Station
Addition of Low-NOx Burners and Overfire Air Systems
Sections 21, 22, 27 and 28, T15N, R19E, Muskogee County
Located Near Muskogee on Hwy. 62 on the East Bank of the Arkansas River
Latitude 35.763°N, Longitude 95.298°W

SECTION I. INTRODUCTION

The Oklahoma Gas & Electric Company (OG&E) has requested a construction permit for modifications to their Muskogee Generating Station to add low-NO_X burners (LNB) and overfire air (OFA) to Units 4 and 5 to reduce emissions of NO_X for the purpose of meeting Best Available Retrofit Technology (BART) requirements. The facility is an electricity generation plant (SIC Code 4911) located in an attainment area. The facility is currently operating under Permit No. 2007-271-TVR (M-2) issued November 23, 2011.

SECTION II. PROJECT DESCRIPTION

OG&E proposes the installation of LNB/OFA technology on Units 4 and 5 to reduce NO_X emissions from the Muskogee Generating Station. LNB and OFA are two forms of combustion control that have been combined in a single technology to reduce NO_X emissions from pulverized coal fired units. NO_X, primarily in the form of NO and NO_2, is formed during combustion by two primary mechanisms; thermal NO_X and fuel NO_X. Thermal NO_X results from the dissociation and oxidation of nitrogen in the combustion air. The rate and degree of thermal NO_X formation is dependent upon oxygen availability during the combustion process and is exponentially dependent upon the combustion temperature. Fuel NO_X, on the other hand, results from the oxidation of nitrogen organically bound in the fuel. Fuel NO_X is the dominant NO_X

producing mechanism in the combustion of pulverized coal and typically accounts for 75 to 80 percent of total NO_X.

All LNBs offered commercially for application to coal fired boilers control the formation of NO_X through some form of staged combustion. The basic NO_X reduction principles for LNBs are to control and balance the fuel and airflow to each burner, and to control the amount and position of secondary air in the burner zone so that fuel devolatilization and high temperature zones are not oxygen rich. In this process, the mixing of the fuel and the air by the burner is controlled in such a way that ignition and initial combustion of the coal takes place under oxygen-deficient conditions, while the mixing of a portion of the combustion air is delayed along the length of the flame. The objective of this process is to drive the fuel-bound nitrogen out of the coal as quickly as possible, under conditions where no oxygen is present, and where it will be forced to form molecular nitrogen rather than be oxidized to NO_X.

OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect of the LNBs and further reducing NO_X emissions. Residual unburned material, such as CO and unburned carbon that inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

The net result of the staged combustion associated with an LNB is usually lower peak combustion temperatures and longer and/or wider flames, due to the delayed mixing process. The lower combustion temperatures and potential for encroachment on cooled boiler surfaces are the main reasons that low-NO_X combustion techniques may be associated with the potential for increased carbon in ash and higher CO emissions. The resulting efficiency loss due to this potential can be somewhat offset, however, by the lower total excess air demand that is part of the low-NO_X firing strategy. Additionally, improved stoichiometric control (air and coal flow monitoring) at the burners will improve combustion by ensuring a better coal/air balance across all of the coal burners, and maintaining coal fineness will allow for good coal burnout.

OG&E's project contractor has guaranteed emission results under specified test conditions of 0.15 lb/MMBTU NOx and 0.37 lb/MMBTU CO for each Unit.

SECTION III. FACILITY DESCRIPTION

The Muskogee Generating Station utilizes sub-bituminous coal, natural gas, and some waste products (used oil-sorb, used antifreeze, used solvents, used oil, chemical cleaning wastes, hazardous waste fuel, activated carbon, demineralizer resin, and waste water treatment sludge) to produce electricity (SIC 4911). The facility includes 3 large boiler units and auxiliary facilities for storage and processing of solid and liquid fuels and for handling ash and other wastes. The Muskogee Units 4, 5 and 6 use natural gas as a start-up fuel and sub-bituminous low-sulfur Wyoming coal as the primary fuel.

The facility became commercially operational in 1956. OG&E has obtained Applicability Determinations for the incineration of some waste products. The facility is a Phase II source for the Acid Rain Program and is located in an attainment area.

The primary air pollution emitting operations are three large boiler units in electrical generation service. Units 4, 5, and 6 are coal-fired units. Units 1, 2, and 3, the oldest units, have been retired or demolished.

There are two operating scenarios for the facility. For Scenario I, Boilers 4, 5, and 6 are fired only with coal. For Scenario II, minor amounts of wastes are added to the coal and burned. This has a negligible effect on overall emissions, therefore, the two scenarios will be considered to have identical emission rates.

Coal is transported to the facility from Wyoming by railroad. A rotary coal car dumper empties railcars onto conveyor belts. These conveyors transport coal to a large pile. Reclaim conveyors move coal as-received to crushers via transfer towers. Coal is reduced in size at the crusher and screened before being conveyed to “tripper galleries” (storage silos) and then to boilers as fuel. Unit 6 also has an intermediate surge bin for crushed coal. Units 4, 5, and 6 can each potentially combust approximately 300 tons per hour of coal to produce 3.8 million pounds per hour of steam each. These units each have a nominal capacity of 550 MW electrical output. During the combustion process, fly ash is collected by electrostatic precipitators. The precipitators are designed to remove 99.52% of the fly ash from the flue gas and collect it in hoppers. The fly ash is then pneumatically conveyed to the silos where it is stored.

The auxiliary boiler uses natural gas to provide steam, as required, to the building heating systems for Unit 3 only. In addition to the primary emission units, there are several support units for fuel and ash handling and storage.

SECTION IV. EQUIPMENT

EUG 1 Facility Wide			
EU ID#	**Point ID#**	**EU Name/Model**	**Construction Date**
None	None	Facility	1956

EUG 3 1972 Boilers			
EU ID#	**Point ID#**	**EU Name/Model**	**Construction Date**
3-B	01	Unit 4 Boiler, 5,480 MMBTUH, Combustion Engineering, S/N 8372	1972
3-B	02	Unit 5 Boiler, 5,480 MMBTUH, Combustion Engineering, S/N 8472	1972

EUG 4 1978 Boiler			
EU ID#	**Point ID#**	**EU Name/Model**	**Construction Date**
4-B	01	Unit 6 Boiler, 5,150 MMBTUH, Combustion Engineering, S/N AA-B0001	1978

EUG 5 Coal Piles			
EU ID#	**Point ID#**	**EU Name/Model**	**Construction Date**
5-B	01, 02, 03, 04	Coal Pile	1972

EUG 6A Coal Unloading & Processing			
EU ID#	**Point ID#**	**EU Name/Model**	**Construction Date**
6-B	01	Rotary Coal Car Dumper	1972
6-B	02	Radial Stacker from Car Dumper	1972
6-B	03	Reclaim Conveyor (Units 4 & 5)	1972

EUG 6B Coal Unloading & Processing			
EU ID#	**Point ID#**	**EU Name/Model**	**Construction Date**
6-B	05	Tripper Gallery (Units 4 & 5)	1972
6-B	07	Reclaim Conveyor (Unit 6)	1978
6-B	10	Crusher (Unit 6)	1978
6-B	11	Transfer Tower #3 (Unit 6)	1978
6-B	06	Linear Stacker (Unit 6)	1978
6-B	08	Transfer Tower #1 (Unit 6)	1978
6-B	09	Transfer Tower #2 (Unit 6)	1978
6-B	04	Crusher (Units 4 & 5)	1972 (mod 2008)
6-B	12	Surge Bin (Unit 6)	1978 (mod 2012)
6-B	13	Tripper Gallery	1978 (mod 2012)

EUG 7 Fly Ash Storage			
EU ID#	**Point ID#**	**EU Name/Model**	**Construction Date**
7-B	01	Fly Ash Silo	1972
7-B	02	Fly Ash Silo	1972
7-B	03	Fly Ash Silo	1982
7-B	04	Fly Ash Silo	1978

EUG 8 Fuel Tanks				
EU ID#	**Point ID#**	**EU Name/Model**	**Capacity (Gallons)**	**Construction Date**
8-B	01	Gasoline	2,000	1993
8-B	02	Diesel (machine shop)	8,300	2003
8-B	03	Diesel (heavy equipment)	7,500	1979
8-B	04	Diesel (heavy equipment)	10,000	1976
8-B	05	Diesel (Unit 3 auxiliary generator)*	750	1970
8-B	06	Diesel (Unit 3 fire pump)*	200	1997
8-B	07	Diesel (Unit 4 fire pump)	300	1997
8-B	08	Diesel (Unit 6 auxiliary generator)	400	1978
8-B	09	Diesel (Unit 4 auxiliary generator)	500	1976
8-B	10	Diesel (Unit 5 auxiliary generator)	500	1976
8-B	11	Liquid fuel day tank*	40,000	1956

*NOTE: Although Unit 3 has been retired, not all of the units supporting it have been removed.

EUG 9 Insignificant Engines					
EU ID#	**Point ID#**	**EU Name/Model**	**Serial Number**	**Capacity (HP)**	**Construction Date**
9-B	01	Detroit Diesel Model 5117982	12VA-11595	710	1970
9-B	03	Cummins Model NT855-F2	10946353	340	1979
9-B	05	Waukesha Model F-2896	288522	710	1976
9-B	04	Waukesha Model F-2896 DSIM	288523	710	1976
9-B	06	Detroit Diesel Model 81637300	16VF002836	710	1978

The last three engines were constructed after October, 1972, and have emissions in excess of 5 TPY based on 500 hours operating. However, the “Insignificant Activities” list does not state the 5 TPY level as being applicable to emergency generators. The engines are exempt from PSD review based on the September 6, 1995 EPA memo, “Calculating Potential to Emit for Emergency Generators” which states that 500 hours is an appropriate default for estimating emissions from these sources. All equipment is, therefore, in compliance with permitting requirements.

EUG 10 New Fire Pump Engine					
EU ID#	**Point ID#**	**EU Name/Model**	**Serial Number**	**Capacity (HP)**	**Construction Date**
10-B	01	Cummins CFP6E	46715829	225	2007

EUG 11	**New Emergency Generator**				
EU ID#	**Point ID#**	**EU Name/Model**	**Serial Number**	**Capacity (HP)**	**Construction Date**
11-B	01	Generac Model 005887-0	NA	25 (20-kW)	2010

SECTION V. EMISSIONS AND EMISSIONS CHANGES

Emissions calculations are divided into two sections, modified boilers and all other units. The modified boilers' emissions calculations will be divided into three sets of factors: actual emissions, post-project emissions, and potential emissions. The first two sets of factors are used in calculating the net emissions changes as Projected Actual Emissions (PAE) minus Baseline Actual Emissions (BAE). No factors are stated pre-project for those pollutants which are monitored continuously: NOx and SO_2.

A. Modified Boiler Emissions

Existing potential emissions have been calculated using the following factors. Except for CO, these are identical to factors used for the current permit. The application stated that the previous CO emissions factor (0.5 lb/ton) would be adjusted based on coal heating value and newer FIRE factors up from 0.019 lb/MMBTU to 0.028 lb/MMBTU. (NOTE: AP-42 (9/98) Section 1.1 provides for adjusting listed emissions factors based on heating value of coal.)

Pollutant	**Emission Factor**	**Factor Reference**
NOx	0.70 lb/MMBTU	OAC 252:100-33
CO	0.028 lb/MMBTU	AP-42 (9/98) Section 1.1
VOC	0.003 lb/MMBTU	AP-42 (9/98) Section 1.1
PM_{10}	0.10 lb/MMBTU	NSPS Subpart D
SO_2	1.2 lb/MMBTU	OAC 252:100-31
CO_2e	143 lb/MMBTU	40 CFR Part 98

Baseline actual emissions were determined from historical operating data, selecting the time periods when the individual units' operations were at their highest during the previous 5 year period preceeding the date a completed application was submitted (December 2007 – November 2009 for Unit 4 and June 2008 – May 2010 for Unit 5). Since NOx, SO_2, and CO_2 are measured directly by continuous emissions monitoring systems (CEMS), no emissions factors are relied upon for determining their Baseline Actual Emissions.

Pollutant	**Emission Factor**	**Factor Reference**
CO	0.028 lb/MMBTU	AP-42 (9/98) Section 1.1
VOC	0.003 lb/MMBTU	AP-42 (9/98) Section 1.1
PM_{10}	0.01973 lb/MMBTU	2006 stack testing
$PM_{2.5}$	0.01251 lb/MMBTU	2006 stack testing

Post-project NOx and CO emissions are based on vendor data. PM and VOC remain the same post-project.

Pollutant	**Emission Factor**	**Factor Reference**
CO	0.37 lb/MMBTU	Vendor estimate
NOx	0.15 lb/MMBTU	Vendor estimate

Projected actual emissions were based on projected usage of each unit and anticipated outages. No demand growth or other exclusions were claimed.

Pollutant	**Baseline Actual Emissions TPY**		**Projected Actual Emissions TPY**		**NET CHANGES TPY**	**PSD Levels of Significance TPY**
	Unit 4	**Unit 5**	**Unit 4**	**Unit 5**		
SO_2	8,891.11	9,086.09	8,793.51	7,895.83	-1,287.86	40
NOx	5,609.38	5,600.30	3,250.03	3,144.63	-4,815.02	40
VOC	56.21	57.28	57.71	57.20	1.42	40
CO	468.38	477.33	6,390.71	6,334.37	11,799.40	100
PM_{10}	328.99	335.27	337.80	334.82	8.36	15
$PM_{2.5}$	208.60	212.58	214.18	212.30	5.30	10
CO_2	3,483,889	3,561,482	3,428,208	3,227,966	-389,197	75,000

Based on the preceding projections and calculations, the project will exceed PSD levels of significance only for CO.

B. Other Units' Emissions

Emission estimates reflect continuous operations (8,760 hr/yr) using emission factors as follows:

- Uncontrolled PM emissions from the modified units 6-B-12 and 6-B 13 were based on AP-42 (5/08), Table 12.2-18 for coal handling at coke production plants: 0.0060 lb/ton. Maximum hourly process rates are 1,200 TPH, while maximum annual process rates are 2,628,000 TPY.

- Emissions from the new emergency generator engine (11-B-01) are based on manufacturer guarantees: NOx, 8.8 g/kW-hr; CO, 86.2 g/kW-hr; and VOC, 1.19 g/kW-hr. SO_2 and PM emissions are expected to be negligible. Maximum annual operations were stated at 100 hours per year.

- Emissions from the new fire pump engine (10-B-01) are based on limitations of NSPS Subpart IIII (NOx + VOC: 7.8 g/hp-hr; CO: 3.5 g/hp-hr, and PM: 0.4 g/hp-hr). Diesel fuel used must meet the specifications of 40 CFR Part 80.510(a) of 500 ppm sulfur, which is equivalent to 0.005 lb/MMBTU or approximately 8.8 E-8 g/hp-hr. Manufacturer guarantees of replacement engine emissions (4.265 g/hp-hr NOx, 0.447 g/hp-hr CO, and 0.075 g/hp-hr PM), and AP-42 (10/96) Section 3.3 (0.00205 lb/hp-hr SO_2 and 0.00251 lb/hp-hr VOC) are all below these emissions levels. Maximum annual operations were stated at 100 hours per year.

- Boiler 6: coal-firing emissions factors as follows: NOx, 0.70 lb/MMBTU (from Subchapter 33), CO, 0.5 lb/ton [AP-42 (9/98), Section 1.1], VOC, 0.05 lb/ton [AP-42 (9/98), Section 1.1 for pulverized coal], PM_{10}, 0.039 lb/MMBTU (derived from a 1978 BACT determination), and SO_2, 1.2 lb/MMBTU (from Subchapter 31).

- Coal processing: PM emissions were taken from AP-42 (1/95), Section 13.2.4, using a wind speed of 2-9.5 mph and a moisture content of 4.5%, and assuming 90% control efficiency of fabric filters.

- Ash handling: PM emissions were calculated based on AP-42 (1/95) Section 13.2.4 for ash handling assuming 90% control efficiency for use of unloading chute.

- Fuel tanks emissions were calculated using the EPA "TANKS4.0" computer program.

- Existing diesel engine emissions were taken from AP-42 (10/96) Section 3.3: NOx 0.031 lb/hp-hr; CO, 0.00668 lb/hp-hr; SO_2, 0.00205 lb/hp-hr; PM_{10}, 0.0022 lb/hp-hr; and VOC, 0.00247 lb/hr-hr.

- HAP emissions from coal burning: factors in AP-42 (9/98) Section 1.1.

POTENTIAL FACILITY EMISSIONS
Pre-Project

Emission	PM_{10}		SO_2		NOx		VOC		CO	
Unit	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
3-B-01	548.00	2,400.24	6,576.0	28,802.9	3,836.0	16,801.7	16.44	72.01	153.44	672.07
3-B-02	548.00	2,400.24	6,576.0	28,802.9	3,836.0	16,801.7	16.44	72.01	153.44	672.07
4-B-01	212.00	928.56	6,180.0	27,068.4	3,605.0	15,789.9	15.00	65.70	150.00	657.00
5-B-01	60.00	19.71	--	--	--	--	--	--	--	--
5-B-02	60.00	19.71	--	--	--	--	--	--	--	--
5-B-03	60.00	19.71	--	--	--	--	--	--	--	--
5-B-04	60.00	19.71	--	--	--	--	--	--	--	--
6-B-01	0.05	0.22	--	--	--	--	--	--	--	--
6-B-02	0.75	3.27	--	--	--	--	--	--	--	--
6-B-03	0.01	0.06	--	--	--	--	--	--	--	--
6-B-04	6.60	14.45	--	--	--	--	--	--	--	--
6-B-05	0.01	0.06	--	--	--	--	--	--	--	--
6-B-06	0.75	3.27	--	--	--	--	--	--	--	--
6-B-07	0.01	0.06	--	--	--	--	--	--	--	--
6-B-08	0.03	0.14	--	--	--	--	--	--	--	--
6-B-09	0.03	0.14	--	--	--	--	--	--	--	--
6-B-10	0.01	0.06	--	--	--	--	--	--	--	--
6-B-11	0.01	0.06	--	--	--	--	--	--	--	--
6-B-12	0.22	0.24	--	--	--	--	--	--	--	--
6-B-13	0.22	0.24	--	--	--	--	--	--	--	--
7-B-01	1.65	7.23	--	--	--	--	--	--	--	--
7-B-02	1.65	7.23	--	--	--	--	--	--	--	--
7-B-03	1.65	7.23	--	--	--	--	--	--	--	--
7-B-04	1.65	7.23	--	--	--	--	--	--	--	--
8-B-01	0.01	0.01	--	--	--	--	--	--	--	--
9-B-01	1.56	0.39	1.46	0.36	22.01	5.50	1.75	0.44	4.74	1.19
9-B-03	0.75	0.19	0.70	0.17	10.54	2.64	0.84	0.21	2.27	0.57
9-B-04	1.56	0.39	2.52	0.63	22.01	5.50	1.75	0.44	4.74	1.19
9-B-05	1.56	0.39	2.52	0.63	22.01	5.50	1.75	0.44	4.74	1.19
9-B-06	1.56	0.39	2.52	0.63	22.01	5.50	1.75	0.44	4.74	1.19
10-B-01	0.20	0.01	0.01	0.01	3.87	0.19	3.87	0.19	1.73	0.09
11-B-01	--	--	--	--	0.39	0.02	0.05	0.01	3.80	0.19
TOTAL	**1,570.5**	**5,860.8**	**19,341.7**	**84,676.6**	**11,379.8**	**49,418.2**	**59.64**	**211.89**	**483.64**	**2,006.75**

POTENTIAL FACILITY EMISSIONS

Post-Project

Emission	PM_{10}		SO_2		NOx		VOC		CO	
Unit	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
3-B-01	548.00	2,400.24	6,576.0	28,802.9	822.0	3,600.4	16.44	72.01	2,027.6	8,880.9
3-B-02	548.00	2,400.24	6,576.0	28,802.9	822.0	3,600.4	16.44	72.01	2,027.6	8,880.9
4-B-01	212.00	928.56	6,180.0	27,068.4	3,605.0	15,789.9	15.00	65.70	150.00	657.00
5-B-01	60.00	19.71	--	--	--	--	--	--	--	--
5-B-02	60.00	19.71	--	--	--	--	--	--	--	--
5-B-03	60.00	19.71	--	--	--	--	--	--	--	--
5-B-04	60.00	19.71	--	--	--	--	--	--	--	--
6-B-01	0.05	0.22	--	--	--	--	--	--	--	--
6-B-02	0.75	3.27	--	--	--	--	--	--	--	--
6-B-03	0.01	0.06	--	--	--	--	--	--	--	--
6-B-04	6.60	14.45	--	--	--	--	--	--	--	--
6-B-05	0.01	0.06	--	--	--	--	--	--	--	--
6-B-06	0.75	3.27	--	--	--	--	--	--	--	--
6-B-07	0.01	0.06	--	--	--	--	--	--	--	--
6-B-08	0.03	0.14	--	--	--	--	--	--	--	--
6-B-09	0.03	0.14	--	--	--	--	--	--	--	--
6-B-10	0.01	0.06	--	--	--	--	--	--	--	--
6-B-11	0.01	0.06	--	--	--	--	--	--	--	--
6-B-12	0.22	0.24	--	--	--	--	--	--	--	--
6-B-13	0.22	0.24	--	--	--	--	--	--	--	--
7-B-01	1.65	7.23	--	--	--	--	--	--	--	--
7-B-02	1.65	7.23	--	--	--	--	--	--	--	--
7-B-03	1.65	7.23	--	--	--	--	--	--	--	--
7-B-04	1.65	7.23	--	--	--	--	--	--	--	--
8-B-01	0.01	0.01	--	--	--	--	--	--	--	--
9-B-01	1.56	0.39	1.46	0.36	22.01	5.50	1.75	0.44	4.74	1.19
9-B-03	0.75	0.19	0.70	0.17	10.54	2.64	0.84	0.21	2.27	0.57
9-B-04	1.56	0.39	2.52	0.63	22.01	5.50	1.75	0.44	4.74	1.19
9-B-05	1.56	0.39	2.52	0.63	22.01	5.50	1.75	0.44	4.74	1.19
9-B-06	1.56	0.39	2.52	0.63	22.01	5.50	1.75	0.44	4.74	1.19
10-B-01	0.20	0.01	0.01	0.01	3.87	0.19	3.87	0.19	1.73	0.09
11-B-01	--	--	--	--	0.39	0.02	0.05	0.01	3.80	0.19
TOTAL	**1,570.5**	**5,860.8**	**19,341.7**	**8,4676.6**	**5,351.8**	**23,015.6**	**59.64**	**211.89**	**4,231.96**	**18,424.1**
NET CHANGE	**0**	**0**	**0**	**0**	**-6,028.0**	**-26,402.**	**0**	**0**	**3,748.3**	**16,417.7**

POTENTIAL FACILITY HAZARDOUS AIR POLLUTANTS EMISSIONS *

Pollutant	Emissions	
	lb/hr	TPY
Acrolein	0.20	0.88
Arsenic	0.29	1.25
Beryllium	0.01	0.06
Cadmium	0.04	0.16
Chromium	0.18	0.79
Formaldehyde	0.17	0.73
Hydrogen Chloride	1065.9	4671.24
Hydrogen Fluoride	132.22	579.46
Manganese	0.34	1.49
Mercury	0.30	1.54
Nickel	1.14	5.02
TOTALS	**1200.79**	**5256.62**

* Worst-case emissions.

The maximum emissions of mercury from sludge burning were stated as the NESHAP Subpart E limitation of 3,200 grams per day (0.294 lb/hr). These rates do not take into account the control efficiency of the boilers' electrostatic precipitators, normally expected to be 50% or more.

POTENTIAL GREENHOUSE GAS EMISSIONS

Unit	CO_2 Emissions, TPY	N_2O		CH_4 Emissions		Total GWP TPY
		Emissions, TPY	GWP	Emissions, TPY	GWP	
Unit 4	62,708,272	81.61	310	528	21	62,744,660
Unit 5	62,708,272	81.61	310	528	21	62,744,660
Unit 6	58,932,044	76.69	310	496	21	58,966,241
TOTALS						184,455,561

GHG emissions were calculated using the methods of 40 CFR Part 98.33c, using maximum hourly heat inputs extrapolated to 8,760 hours per year operation.

STACK PARAMETERS

Point	Height Feet	Diameter feet	Flow ACFM	Temperature °F
Boiler 4	350	24	1,259,309	264
Boiler 5	350	24	1,259,309	264
Boiler 6	500	21.5	1,803,588	264

SECTION VI. PSD REVIEW

As shown, the proposed project will increase emissions above the PSD significance level for carbon monoxide, which is subject to further review below. Full PSD review of emissions consists of the following.

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 impacts.

The project is heavily influenced by NOx reductions needed to achieve BART compliance. There is an inverse relationship between NOx and CO emissions, i.e., procedures which reduce NOx result in increased CO emissions, and vice versa. Therefore, although the proposed BACT does not equal the lowest rates for retrofit units, NOx emissions are among the lowest. Higher CO emissions rates are acceptable in context of lowered NOx emissions. Recent BACT determinations will be shown demonstrating that the higher CO proposed in this application are offset by better NOx reductions.

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.

Step 1: Identify All Control Technologies

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. The primary technical challenge faced with trying to install an oxidation catalyst on a coal fired boiler is that 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.

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. Typically, the measures taken to minimize the formation of NO_X during combustion (such as the installation of LNB/OFA) tend to inhibit complete combustion, which increase 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.

Step 2: Eliminate Technically Infeasible Options

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.

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 OG&E is not aware of this control technology's ever having been applied to a solid fuel boiler. Technical challenges that render an oxidation catalyst control technically infeasible for Units 4 and 5 include the following.

- The oxidation catalyst will not only oxidize CO, but will also oxidize a predominant portion of SO_2 to SO_3, which forms corrosive and undesirable sulfuric acid vapor emissions in the presence of water. Additionally, if additional controls such as an SNCR/SCR were installed on Units 4 and 5, even more SO_2 would be oxidized to SO_3 and would likely result in the quick fouling of the air heater and equipment corrosion downstream.
- 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.

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.

Step 3: Rank Remaining Control Technologies by Effectiveness
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).
- 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 since 2005. 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. 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 exhibit 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 are 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.

CO Requirement	Averaging Period	Facility/Unit Name	State	Date
0.17 lb/MMBTU	30-day rolling	GRDA Chouteau (#1 and #2)	OK	7/12
0.17 lb/MMBTU	30-day rolling	KCK's Nearman Creek Power Sta (#1)	KS	4/11
0.42 lb/MMBTU	30-day rolling	KCK's Quindaro Power Sta (#2)	KS	4/11
0.34 lb/MMBTU	unknown	SWEPCO'sTolk Sta Power Plant	TX	3/11
0.30 lb/MMBTU	24-hour	Consumers Energy's Tes Filer City Plt	MI	6/10
0.15 lb/MMBTU	30-day rolling	Minnesota Power Div Allete Boswell	MN	4/10
0.33 lb/MMBTU	unknown	NRG's Limestone Plant	TX	2/10
0.33 lb/MMBTU	30-day rolling	SouthWest PSO's Harrington Sta #1	TX	1/10
0.149 lb/MMBTU	unknown	Mississippi Power Co Jack Watson	MS	9/09
0.25 lb/MMBTU	30-day rolling	Pacificorp's Wyodak Plant (Unit 1)	WY	5/09
0.25 lb/MMBTU	30-day rolling	Pacificorp's Naughton Plant (#1 and #2)	WY	5/09
0.50 lb/MMBTU	30-day rolling	Omaha Public Power District's (OPPD) Nebraska City Station	NE	2/09
0.50 lb/MMBTU	30-day rolling	Salt River Project's Coronado Generating Station (Units 1 and 2)	AZ	1/09
0.25, 0.20 lb/MMBTU	30-day rolling	Pacificorp's Dave Johnston Plant (Units 3 and 4, respectively)	WY	6/08
0.25 lb/MMBTU	30-day rolling	Westar Energy's Tecumseh Energy Ctr	KS	11/07/
0.163 lb/MMBTU	30-day rolling	Iowa Power and Light's (IPL) Ottumwa Generating Station	IA	2/07
0.20 lb/MMBTU	30-day rolling	Lakeland Electric's McIntosh Plant	FL	12/06
0.20 lb/MMBTU	30-day rolling	Cleco Corp's Dolet Hills Power Station	LA	11/06
0.15 lb/MMBTU	8-hour rolling	Platte River Power Authority's Rawhide Energy Station	CO	9/06
0.50 lb/MMBTU	30-day rolling	Nebraska Public Power District's Gerald Gentleman Station (Unit 1)	NE	8/06
0.25 lb/MMBTU	30-day rolling	Westar Energy's Jeffrey Energy Ctr	KS	10/05
0.42 lb/MMBTU	calendar day	MidAmerica Energy's Neal Energy Center South	IA	9/05

OG&E has requested that the following determinations be excluded from the study. The first four have SCR in addition to low-NOx burners, and the fifth is the highest. With NOx controls present elsewhere, less effect from overfire air must be realized.

CO Requirement	Averaging Period	Facility/Unit Name	State	Date
0.02 lb/MMBTU	unknown	Pacificorp's Naughton #3	WY	5/09
0.18, 0.15 lb/MMBTU	30-day rolling	Orlando Utilities Commission's Stanton Energy Center (Units 1 and 2)	FL	2/08
0.17 lb/MMBTU	30-day rolling	Progress Energy's Crystal River Plant (Units 4 and 5)	FL	5/07
0.20 lb/MMBTU	30-day rolling	Tampa Electric Company's Big Bend Station (Unit 4)	FL	5/07
0.35 lb/MMBTU	30-day rolling	City Utilities of Springfield's James River Power Station (Units 3, 4, and 5)	MO	12/06
1.26 lb/MMBTU	3-hour	MidAmerica Energy's George Neal North Plant (Unit 1)	IA	12/05

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 OG&E's Muskogee Station. 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 Muskogee Units 4 and 5, 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 determinations were extracted from the previously mentioned list to illustrate determinations recently made by permitting authorities for retrofit projects similar to that proposed for OG&E's Muskogee Units 4 and 5.

Recent BART / PSD Determinations

Facility	**State**	**Date**	**CO lb/MMBTU**	**NOx lb/MMBTU**
Salt River Project Coronado #1	AZ	1/09	0.50	0.32
Platte River Power Authority Rawhide #1	CO	9/06	0.15	0.18
Mid-America George Neal South Plant No. 4	IA	9.05	0.42	0.46
Iowa Power & Light Ottumwa	IA	2/07	0.163	0.3
Westar Energy Jeffrey Energy Ctr #3	KS	2011	0.4	0.14
KCK Nearman Creek Power St #1	KS	4/11	0.17	0.26
KCK Quindaro Power Sta #2	KS	4/11	0.42	0.18
Consumers Energy Tes Filer City Plt	MI	6/10	0.3	0.6
City of Springfield James River Units 3, 4, 5	MO	12/06	0.35	0.2
Mississippi Power Co Jack Watson #4 & #5	MS	9/09	0.149	0.50
Nebraska Public Power Gentleman Station #1	NE	8/06	0.50	0.5
OPPD Nebraska City Station #1	NE	2/09	0.50	0.23
GRDA Chouteau #1 & #2	OK	7/12	0.17	0.25
SWECP Harrington Station #1	TX	1/10	0.33	0.40
NRG Limestone Plant #1 & #2	TX	2/10	0.33	0.25
SWEPCO Tolk Station Power Plant	TX	3/11	0.34	0.35
Pacificorp Dave Johnson #3 & #4	WY	6/08	0.25	0.28
Pacificorp Naughton Plant #1 & #2	WY	5/09	0.25	0.26
Pacificorp Wyodak Plant Unit #1	WY	5/09	0.25	0.23

These determinations, spanning the last six-plus years, range from 0.15 to 0.50 lb/MMBTU for tangentially-fired units, with an average CO BACT emission rate of approximately 0.33 lb/MMBTU. All but eight of the CO BACT determinations specified above require a 30-day rolling average as a basis for compliance. The top, and only control technology determination listed, is the use of GCC for the reduction of CO emissions from coal fired boilers.

Step 4: Evaluate Most Effective Controls and Document 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 Units 4 and 5, a comparative cost analysis is not applicable.

Step 5: Select BACT

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, OG&E proposes the only feasible control; GCC, for the control of CO emissions resulting from the LNB/OFA Project for Muskogee Units 4 and 5. The proposed BACT for CO on Units 4 and 5 is good combustion controls to achieve an emission limit of 0.37 lb/MMBTU, based on a 30-day rolling average.

The proposed BACT determination is supported by the USEPA RBLC Clearinghouse database review presented earlier, where good combustion control practices and an average BACT determination of 0.37 lb/MMBTU for recently permitted LNB/OFA retrofit projects are documented as BACT for CO.

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

<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 AERMOD (Version 12060) air dispersion model is used to predict maximum ground-level concentrations associated with the proposed project's emissions. AERMOD is a refined, multi-source Gaussian plume model. The modeling analysis was performed using regulatory default options including stack-tip downwash and missing data processing.

<u>Source Input Parameters</u>

The stack heights for both Units 4 and 5 are 350 ft. The modeled CO emission rate is based on a 0.37 lb/MMBTU emission rate and each unit's heat input of 5,480 MMBTU/hr, respectively.

<u>Good Engineering Practice and Building Downwash Evaluation</u>

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.

The model utilizes the EPA Building Profile Input Parameters (BPIP) program with the plume rise model enhancements (PRM). BPIP-PRM determines the effect of building downwash on each plume in calculation of maximum impacts.

Meteorology and Surface Characteristics

Five years (2006, 2007, 2008, 2009, and 2010) of processed Oklahoma Mesonet data from Porter, Oklahoma were combined with data from the National Climatic Data Center (NCDC) and Norman Max Westheimer Airport (OUN; 72357-3948) Upper Air (UA) rawinsonde observation (RAOB) data from the Forecast System Laboratories (FSL). Oklahoma Mesonet data was provided to the AQD courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University (OSU) and the University of Oklahoma (OU) and supported by the taxpayers of Oklahoma.

When using AERMET to prepare the meteorological data for AERMOD, the surface characteristics (Albedo, Bowen Ratio, and Surface Roughness Length) for the primary (MESONET) and secondary (NCDC-ISD) meteorological sites were determined using AERSURFACE (Version 08009).

Terrain Considerations

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.
- 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)

Urban/Rural Classification

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 Muskogee 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 AERMOD PRIME model.

Discrete and Flagpole Receptors

The AERMOD 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.

Six Cartesian grids for the modeling analyses were defined as follows:

1. A Fence Line Grid containing receptors spaced at 50 meter intervals along the facility fence line.
2. A Fine Grid containing receptors spaced at 100 meter intervals extending approximately 1.0 km from the fence line, exclusive of the Fence Line Grid.
3. A 250-meter grid containing receptors spaced at 250 meter intervals extending approximately 2.5 km beyond the Fine Grid.

4. A 500-meter grid containing receptors spaced at 500 meter intervals extending approximately 5.0 km beyond the 250-meter grid.
5. A 750-meter grid containing receptors spaced at 750 meter intervals extending approximately 7.5 km beyond the 500-meter grid.
6. A 1,000-meter grid containing receptors spaced at 1,000 meter intervals extending approximately 50.0 km beyond the 750-meter grid.

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).

Pollutant	Averaging Period	SIL $\mu g/m^3$	Max Impact $\mu g/m^3$	Full Impact Analysis Required?
CO	1-hr	2,000	860	No
	8-hr	500	250	No

C. Evaluation of PSD increment consumption

Because the project impact is less than the SIL, 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)

Because the project impact is less than the SIL, 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. Because the preceding table shows that the project's maximum-modeled predicted CO 8-hour impact is less than the PSD significant monitoring concentration (575 $\mu g/m^3$), the applicant requests exemption from PSD pre-application monitoring requirements.

F. Evaluation of source-related impacts on growth, soils, vegetation, visibility

The facility has provided a brief review of these topics.

Commercial, Residential, and Industrial Growth Analysis

The project is located in Muskogee County in an area zoned as industrial. Because the project will not create additional generating capacity, the project will not have a significant effect upon the industrial growth in the immediate area. There will be an increase in the local labor force during the construction phase of the project. It is anticipated that most of the labor force during the construction phase will commute from nearby communities. This labor force increase will be temporary, short-lived, and will not result in permanent commercial and residential growth occurring in the vicinity of the project.

The potential for housing shortages and thus the possibility of housing related growth and secondary air quality impacts have been an issue historically for the construction of large coal plants in sparsely populated areas. However, experience has also shown that smaller projects (modifications) like the proposed project located in or near urban areas typically have no noticeable impacts on the housing market. The reason is that impacts are primarily a function of the size of the construction workforce and the need for the workforce to relocate during construction.

The need to relocate is a function of the available workforce within a reasonable commuting distance of the work site. Research by the Electric Power Research Institute (EPRI) has indicated that the construction workforce for a power plant project can reasonably be expected to commute without relocating during construction from a distance of more than 70 miles, with instances of a commuting distance of more than 100 miles found in each of the construction projects studied. When a 70 mile radius around the Muskogee Station site is considered, areas including Tulsa and Muskogee in Oklahoma are within commuting distance to the site.

The area offers a wide variety of temporary lodging. Given the expected population of the commuting workforce, the fact that during the construction period most workers will be onsite for less than the total construction period, and an abundance of hotel and other short-term lodging options in Muskogee County, it is unlikely that a substantial number of the construction workforce would choose to relocate during the construction period. Therefore, the anticipated housing growth will be minimal or nonexistent, and is not expected to have a significant impact on the air quality.

Population increase is a secondary growth indicator of potential increases in air quality levels. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. Since there will be no or only minimal number of new, permanent jobs created by the project, secondary residential, commercial, and industrial growth is not expected to have a significant impact on the air quality.

Finally, because the maximum model-predicted CO concentrations for the proposed project are well below the NSR/PSD significant impact levels, air concentrations in the region are expected to fully comply with the ambient air quality standards when the proposed project becomes operational. Therefore, from an air quality impact standpoint, the proposed project is consistent with the balanced growth demonstrated by the county to date.

Visibility Impairment Analysis

An additional impacts visibility analysis may be used to determine if the emissions increases associated with a proposed PSD project will have an impact on Class I sensitive areas such as state parks, wilderness areas, or scenic sites and over looks. However, because the proposed project does not result in any increase of a visibility impairing pollutant, and because the Muskogee Station is not located within 40 km of a sensitive area, an additional impacts visibility impairment analysis is not required for this project. An explanation of these issues is presented in the following paragraphs.

The screening model VISCREEN can be used to perform a visibility analysis for Class II areas. The VISCREEN model uses emissions of primary particulate matter (PM), nitrogen oxides (NO_X), primary nitrogen dioxide (NO_2), soot (elemental carbon), and primary sulfate (SO_4^-) to determine the visibility impacts from the emissions associated with the proposed project. However, the only pollutant that results in a significant net emissions increase is CO, which is a non-visibility impairing pollutant. Therefore, the project is not predicted to negatively impact visibility.

Furthermore, a review of the Class I areas around the Muskogee Station does not show any sensitive areas within 40 km. The nearest ODEQ listed sensitive area is the Wichita Mountains Wildlife Refuge, which is approximately 290 km from the Muskogee Station. The Osage Indian Reservation is approximately 80 km from the site, which is the closest state/national park or Indian reservation area to the Muskogee Station; however, the Osage Reservation is not expected to be impacted for visibility by CO.

Vegetation Analysis

The NSR Workshop Manual states that the analysis of air pollution impacts on vegetation should be based on an inventory of species found in the impact area, i.e., significant impact area (SIA). Since the emissions from the proposed project did not result in any exceedances of the significant impact levels; thus no SIA exists.

Unlike fauna, CO does not poison vegetation since it is rapidly oxidized to form carbon dioxide which is used for photosynthesis. However, extremely high concentrations can reduce the photosynthetic rate. According to the USEPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals*, hereafter referred to as USEPA Screening Document, for the most sensitive vegetation, a CO concentration of 1,800,000 $\mu g/m^3$ (1-week averaging period) could potentially reduce the photosynthetic rate. The maximum model-predicted 1-hour CO impact of 860 $\mu g/m^3$ produced by the proposed project is significantly lower than this screening level (even at a conservative 1-hour averaging period). Consequently, no adverse impacts to vegetation at or near the proposed project are expected from CO emissions.

Soils Analysis

As noted earlier, the maximum model-predicted ambient concentration of CO resulting from the project is 860 $\mu g/m^3$, which is significantly less than the applicable ambient air quality standards and the NSR/PSD significant impact levels. Because the predicted CO air quality impacts resulting from the project are not significant, and are in fact orders of magnitude less than the applicable air quality standards designed to protect public health, it is reasonable to conclude that the proposed emissions of CO will not affect soils.

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. The Muskogee Station is approximately 290 km from the closest Class I area, the Wichita Mountains Wildlife Refuge. Other Class I areas in proximity to the Muskogee Station include the Caney Creek Wilderness Area also located in Arkansas and the Hercules-Glades Wilderness Area in Missouri. As the proposed project results in a substantial decrease in NO_X emissions and no increase in any other visibility impairing pollutants (i.e., SO_2, PM_{10}, and H_2SO_4), a Class I area analysis is not required for this project.

The nearest Class I area is the Wichita Mountains Wildlife Refuge in southwest Oklahoma. The Federal Land Managers (FLM) for Class I Areas have proposed new guidance that uses the 10D Rule ($Q/D<10$). In this equation, Q is equal to the sum of the emission increases of NO_X, SO_2, H_2SO_4, and PM_{10} that will result from the proposed project (in TPY). The variable D is the distance from the source to the Class I Area (in km), and must be greater than 50 km. If the calculated Q/D value exceeds 10, then a Class I area analysis evaluating Air Quality Related Values (AQRV) (deposition and visibility) must be conducted. Otherwise, no additional analyses are required. CO is not among the variables and all other pollutants will decline. There will be no impact on the Class I area visibility.

SECTION VII. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application and listed in OAC 252:100-8, Appendix I, are listed below. Recordkeeping for activities indicated with "*" is listed in the Specific Conditions. Any activity to which a state or federal applicable requirement applies is not insignificant even if it is included on this list.

* Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power or for peaking power service not exceeding 500 hours/year. There are four emergency generators and a diesel-powered fire water pump in this category (EUG No. 9).

* Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period. The facility has gasoline and diesel fueling operations.

* Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature. There are several small diesel tanks in EUG No. 8 in this category.

Cold degreasing operations utilizing solvents that are denser than air.

Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes. These activities are conducted as a part of routine maintenance and are considered trivial activities. Recordkeeping will not be required in the Specific Conditions.

Hazardous waste and hazardous materials drum staging areas.

Sanitary sewage collection and treatment facilities other than incinerators and Publicly Owned Treatment Works (POTW). Stacks or vents for sanitary sewer plumbing traps are also included (i.e., lift station).

Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas. The facility includes a chemical storage area for the maintenance operations.

Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas.

* Activities having the potential to emit no more than 5 TPY (actual) of any criteria pollutant. Fugitive emissions from the following operations are below 5 TPY:

Rotary Coal Car Dumper	Fly Ash Silos
Coal Stacker Tower	Auxiliary Boiler (Scenario I & II)
Coal Reclaim	Coal Surge Bin
Coal Crusher Tower	Coal Transfer Tower

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. 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.

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 (Operating Permits (Part 70)) [Applicable]
This facility meets the definition of a major source since it has the potential to emit regulated pollutants in excess of 100 TPY. As such, a Title V (Part 70) operating permit is required. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I <u>or</u> whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant,
- 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 permit application, or developed from the applicable requirement.

OAC 252:100-9 (Excess Emission 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 affirmative defense, 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) [Applicable]
This subchapter specifies limits for fuel-burning equipment particulate emissions based on heat input capacity. Emissions limitations and anticipated emissions are tabulated following. Emissions listed for the boilers are based on the allowable emissions. All units are in compliance with Subchapter 19.

COMPLIANCE WITH OAC 252:100-19

Emission Unit	Description	Capacity, MMBTUH	Allowable PM Emissions, lb/hr	Calculated PM Emissions, lb/hr
3-B-01	Boiler 4	5480	656.8	17.25
3-B-02	Boiler 5	5480	656.8	17.25
4-B-01	Boiler 6	5150	628.9	212.00

Expected PM emissions from Boilers 4 and 5 were calculated based on a coal feed rate of 300 TPH, an average ash content of 5%, AP-42 (9/98) Section 1.1 uncontrolled emission factor of “2.3*A” for pulverized coal units, and a control efficiency of 99.5%. For Boiler 6, emissions were based on an assumed coal burning rate, assumed ash content, assumed partition of flyash to total ash, and assumed control efficiency.

Subchapter 19 also limits PM emissions from various processes excluding fuel-burning equipment and fugitive emissions. Limitations are specified based on process weight rate. Emissions limitations and anticipated emissions are tabulated following. All units are in compliance with Subchapter 19.

COMPLIANCE BY MINOR PM EMISSION UNITS WITH OAC 252:100-19

Process Point	Process Rate, TPH	Allowable PM Emission Rate, lb/hr	Controlled Emission Rate, lb/hr
6-B-04	1200	80.0	6.60
6-B-05	1200	80.0	0.01
6-B-08	3000	92.69	0.03
6-B-09	3000	92.69	0.03
6-B-10	1200	79.97	0.01
6-B-11	1200	79.97	0.01
6-B-12	1200	79.97	0.22
6-B-13	1200	79.97	0.22
7-B-01	15	25.2	1.65
7-B-02	15	25.2	1.65
7-B-03	15	25.2	1.65
7-B-04	15	25.2	1.65

The controlled emission rates show that the facility is in compliance with Subchapter 19.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for 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. Any unit which is subject to an NSPS opacity limitation is not subject to Subchapter 25; this would include Units 4, 5, and 6, as well as the coal handling equipment in EUG 6B. All other emissions units are subject to Subchapter 25. The permit will require weekly observation of the coal processing equipment, and daily observations of the Boiler 3 stack whenever fuel oil is burned; the permit will require opacity testing to be conducted using Method 22 initially, and if any visible emissions are observed, using Method 9.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit 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. Water sprays and enclosures are used on conveyor transfer points and stockpiles to minimize emissions of fugitive dust as required by Subchapter 29.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lbs/MMBTU heat input. Units 4, 5, and 6 are subject to these standards. Solid-fueled units are limited to 1.2 lb/MMBTU SO_2 emissions. Emissions monitoring as required by NSPS, Subpart D has shown compliance with this rule. Engines 9-B-02 through 9-B-06, liquid fueled units, are subject to a limitation of 0.8 lb/MMBTU SO_2. Using No. 2 diesel with 0.5% or less sulfur, SO_2 emissions will be 0.5 lb/MMBTU or less. These emissions are in compliance with Subchapter 31.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter also limits NOx emissions from new solid fuel-burning equipment with a rated heat input greater than 50 MMBTUH to 0.7 lb/MMBTU. This standard is applicable to Boilers 4, 5, and 6 but not to Boiler 3, which predated this rule, nor to the Auxiliary Boiler, which is smaller than the 50 MMBTUH threshold. The PSD permit for Boiler 6 specifies an identical emission limitation to Subchapter 33 and to NSPS, Subpart D. Emissions monitoring has shown compliance with the applicable emissions limitations.

OAC 252:100-37 (Volatile Organic Compounds) [Part 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 2,000-gallon gasoline tank predated the submerged fill requirement. The 40,000-gallon fuel oil storage tank, emergency generator fuel tanks, and diesel vehicle fuel tank have vapor pressures of 0.01 psia, therefore these requirements are not applicable.
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 exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (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.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-11	Alternative Reduction	not eligible
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-21	Wood-Waste Burning	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Feed & Grain Facility	not in source category
OAC 252:100-39	Nonattainment Areas	not in a subject area
OAC 252:100-47	Landfills	not type of emission unit

SECTION IX. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
The Muskogee Generating Station 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 found in Section VI above.

NSPS, 40 CFR Part 60 [Subparts D, Y, JJJJ, and IIII Are Applicable]
Subpart D (Fossil-Fuel-Fired Steam Generators) is applicable to steam generating units constructed after August 17, 1971, which have a capacity greater than 250 MMBTU/hr heat input. Boilers No. 4, 5, and 6 each has a heat input rate of 5,480 MMBTUH and commenced construction in 1972, 1972, and 1978, respectively, therefore are subject to the emissions limitations and emissions monitoring standards.
Subpart Da (Electric Utility Steam Generating Units) affects electric steam generating units with a design capacity greater than 250 MMBTUH, and combined cycle gas turbines that are capable of combusting more than 250 MMBTUH level in the heat recovery steam generator, that were constructed after September 18, 1978; and combined cycle gas turbines capable of combusting more than 250 MMBTUH heat input of fossil fuel (either alone or in combination with any other fuel), designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis that were constructed after February 28, 2005. Subpart Da affects emissions of NOx, SO_2, and PM. Since none of these pollutants are being increased, the facility is not being "modified" as defined by NSPS.
Subpart K (VOL Storage Vessels) The 40,000-gallon fuel oil tank was installed in 1956 which is prior to the applicable time period of June 11, 1973 to May 19, 1978.
Subpart Kb (VOL Storage Vessels) The 2,000-gallon gasoline tank is below the 19,813-gallon threshold for this subpart.

Subpart Y (Coal Preparation Plants) This facility handles up to 7,200 tons of coal per day per unit, and has coal storage systems and coal processing and conveying equipment, which are defined as affected sources per 40 CFR 60.250(a). The coal processing equipment for Unit 6 was constructed after 1978, and the Unit 4/5 crusher was modified by removal of an existing baghouse, therefore, Subpart Y affects that part of the facility. Most of the remainder of the coal processing and handling equipment was constructed in 1972, so Subpart Y is not applicable to that part of the facility.

Subpart HHHH (Coal-Fired Electric Steam Generating Units) Subpart HHHH established as “mercury budget” for states and coal-fired electric generating units. This was part of the CAMR Rule which was vacated by a federal court on February 8, 2008. This permit may be reopened to address Subpart HHHH if the regulation is re-promulgated.

Subpart IIII (Stationary Compression Ignition Internal Combustion Engines) affects stationary compression ignition (CI) internal combustion engines (ICE) based on power and displacement ratings, depending on date of construction, 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. Subpart IIII limits the sulfur content of diesel fuel to 500 ppm, and specifies limits of NOx, CO, VOC, and PM emissions. The new fire pump (EU 10-B-01) is subject to this regulation.

Subpart JJJJ (Stationary Spark Ignition Internal Combustion Engines (SI-ICE)) promulgates emission standards for new SI engines ordered after June 12, 2006 and all SI engines modified or reconstructed after June 12, 2006, regardless of size. The specific emission standards (either in g/hp-hr or as a concentration limit) vary based on engine class, engine power rating, lean-burn or rich-burn, fuel type, duty (emergency or non-emergency), and manufacture date. Engine manufacturers are required to certify certain engines to meet the emission standards and may voluntarily certify other engines. An initial notification is only required for owners and operators of engines greater than 500 HP that are non-certified. The new propane-fired emergency generator (EU 11-B-01) is certified to meet the standards of Subpart JJJJ: 10 g/hp-hr NOx+HC and 387 g/hp-hr CO.

NESHAP, 40 CFR Part 61 [Applicable]

Subpart E (Mercury Emissions) affects combustion of water treatment sludge, limiting mercury emissions to 3,200 grams per day from any such operation. The applicant has requested permission to use an alternative method of testing sludge from the method specified in 40 CFR 61.54. OG&E has attempted to find a laboratory capable of performing this method, but has not been able to find one. They have requested use of SW-846 Method 7471A. Alternative testing methods are allowed under 40 CFR 61.13. The specific conditions will allow use of the alternative method.

NESHAP, 40 CFR Part 63 [Subpart ZZZZ Applicable]
Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart previously affected only RICE with a site-rating greater than 500 brake horsepower that are located at a major source of HAP emissions. On January 18, 2008, the EPA published a final rule that promulgates standards for new and reconstructed engines (after June 12, 2006) with a site rating less than or equal to 500 HP located at major sources, and for new and reconstructed engines (after June 12, 2006) located at area sources. Owners and operators of new or reconstructed engines at area sources and of new or reconstructed engines with a site rating equal to or less than 500 HP located at a major source (except new or reconstructed 4-stroke lean-burn engines with a site rating greater than or equal to 250 HP and less than or equal to 500 HP located at a major source) 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). The new emergency generator is subject to NSPS Subpart JJJJ, therefore, those standards are applicable.
On March 3, 2010, EPA finalized additional requirements for stationary CI RICE. A summary of these requirements for the emergency generator engines located at this facility are shown below.

Engine Category	**Normal Operation @ 15% O_2**
Existing Emergency CI & Black Start CI	Change oil and filter every 500 hours of operation or annually, whichever one comes first; Inspect air cleaner every 1,000 hours of operation or annually, whichever one comes first; and Inspect all hoses and belts every 500 hours of operation or annually, whichever one comes first and replace as necessary.

Sources have the option to utilize an oil analysis program in order to extend the specified oil change requirements of this subpart. Initial compliance demonstrations must be conducted within 180 days after the compliance date. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.

Other applicable requirements include:

1) The owner/operator must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer’s emission-related written instructions or develop their own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
2) Existing emergency stationary RICE located at an area source of HAP emissions must install a non-resettable hour meter if one is not already installed.

Existing stationary CI RICE must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. The permit will require the facility to comply with all applicable requirements by the initial compliance date.

Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters at major sources of HAPs. This regulation was recently re-promulgated. It exempts any boiler facility which is subject to another MACT such as Subpart UUUUU.

Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units. This regulation was promulgated with a compliance date for existing sources of April 16, 2015.

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. This facility is a major source and is not subject to this subpart.

CAM, 40 CFR Part 64 [Applicable]
This part applies to any pollutant-specific emissions unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 18, 1998, that addresses "large emissions units," or any application that addresses "large emissions units" as a significant modification to an operating permit, or for any application for renewal of an operating permit, if it meets all of the following criteria.

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY or 10/25 TPY of a HAP

Boilers 4, 5, and 6 all have controlled emissions of PM exceeding 100 TPY and utilize an "active" control to meet their PM emissions limits. CAM requirements for the large boilers are detailed in the Specific Conditions.

The facility is currently required to measure opacity by both CAM and NSPS Subpart D requirements. This permit will also require monitoring of power supplied to the ESPs and periodic stack testing of PM emissions. According to EPA's Air Pollution Engineering Manual, efficiency of ESPs correlates to the power input. OG&E supplied historical power data, and operating ranges were established as the mean power input plus or minus three standard deviations. Final confirmation of the operating ranges will be done by stack testing.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
This facility does not store any regulated substance above the applicable threshold limits. More information on this federal program is available at the web site: http://www.epa.gov/ceppo/.

Acid Rain Permit Requirements, 40 CFR Part 72 [Applicable]
Acid Rain Permit No. 2004-185-ARR was issued on October 29, 2004, which satisfies the permit requirements.

Acid Rain Monitoring Requirements, 40 CFR Part 75 [Applicable]
Boilers 4, 5, and 6 are Phase II Acid Rain units. Continuous emissions monitoring systems (CEMS) were certified on December 16-19, 1994, for Units 4, 5, and 6.

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.

SECTION XI. COMPLIANCE

Tier Classification And Public Review

This application has been determined to be Tier II based on the request for a construction permit for a "significant" modification for an existing 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 real property.

The "Notice of Filing Tier II Application" was published in the *Muskogee Phoenix* on October 1, 2012. The notice stated that the application was available for review at the Muskogee Public Library, 801 W. Okmulgee, Muskogee, OK. The facility is located within 50 miles of the Oklahoma-Arkansas border; the state of Arkansas was notified of the draft permit. The permit has been approved for concurrent public and EPA review. The "Notice of Draft Tier II Permit" was published in the *Muskogee Phoenix* on December 14, 2012. The notice stated that the application was available for review at the Muskogee Public Library. No comments were received from the public or adjacent state. However, EPA Region VI had two comments:

COMMENT 1: Please provide a complete rationale for the proposed BACT of 0.37 lb/MMBtu for CO for OG&E-Muskogee Units 4 and 5. Specifically, this proposed limit appears high in light of our search of the RACT/BACT/LAER Clearinghouse (RBLC), which found CO emissions limits in the range of 0.15 to 0.25 lb/MMBTU for similar sizes and type of coal-fired units. (See attached table.) Please provide the State's rationale for why the permitted CO emission limits in the attached table are not achievable for Units 4 and 5.

It is true that CO emissions are noticeably higher than some recent BACT determinations. However, BACT determinations are made based on comparable projects and units. For this unit this would include retrofit projects on tangentially-fired units for the purpose of maximizing NOx reductions. CO and NOx emissions are inversely related; to achieve NOx as low as 0.15 lb/MMBTU, a higher CO emission value must be accepted.

The table of BART determinations on Page 17 deals solely with BART determinations. Most of the determinations on Page 17 show noticeably higher NOx than Muskogee Units 4 and 5.

Based on the entire review conducted and the intended purpose of the BART project, ODEQ feels the proposed BACT level is justified.

COMMENT 2: When calculating pre-project "Baseline Actual Emissions" for a modified electric utility steam generating unit, you should include fugitive emissions and emissions associated with Startup, Shutdown and Malfunctions (SSM). See 40 CFR 51.116(b)(47)(i)(a). Please confirm that your pre-project emissions for this project include fugitive and SSM emissions.

We have confirmed with OG&E that all emissions have been incorporated into the baseline.

Information on all permit actions is available for review by the public in the Air Quality section of the DEQ Web page:*http://www.deq.state.ok.us/.*

Inspection

A full compliance evaluation inspection was conducted on June 28, 2010. Ms. Brandie Czerwinski of the Regional Office at Tulsa who was accompanied by Mr. Chuck Smithson, Envirochemical Supervisor for OG&E, conducted the inspection. The facility was physically as described in the permit application and supplemental materials.

Fees Paid

Construction permit application fee of $5,000.

SECTION XI. SUMMARY

The facility has demonstrated the ability to comply with the requirements of the several air pollution control rules and regulations. Ambient air quality standards are not threatened at this site. There is a current Enforcement issue which is unrelated to this permit. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Oklahoma Gas & Electric Company
Muskogee Generating Station **Permit Number 2005-271-C (M-5)(PSD)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on September 21, 2011. The Evaluation Memorandum dated January 22, 2013, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit 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: [OAC 252:100-8-6(a)]

EUG 3 1972 Boilers:

A. Boilers No. 4 and 5 shall have the following emission limitations:
[40 CFR 60.42(a)(1), 43(a)(2), and 44(a)(3)]

Emission Unit	PM lbs/MMBTU	SO_2 lbs/MMBTU	NO_X lbs/MMBTU	Opacity* %
3-B-01	0.10	1.2	0.7	20
3-B-02	0.10	1.2	0.7	20

* opacity shall be limited to 20% except for one six minute period per hour of not more than 27%. [40 CFR 60.42(a)(2)]

B. Boilers 4 and 5 are subject to NSPS Subpart D and shall comply with all applicable requirements. [OAC 252:100-2-3(a)]

C. The permittee shall operate and maintain the continuous monitoring systems for Boiler 4 and 5 using the applicable methods and procedures set forth and shall record the output of the systems. [40 CFR 60.45(a)]

D. Boilers 4 and 5 are authorized to utilize coal as primary fuel and natural gas as startup fuel. [OAC 252:100-31]

E. Compliance with the SO_2 lb/MMBTU emission limits in Specific Condition 1 shall be determined on the basis of the average emission rate for three successive boiler operating hours, a 3-hour rolling average. [40 CFR 60.43]

F. Compliance with the NO_X lb/MMBTU emission limits shall be determined on the basis of the average emission rate for a 3-hour rolling average. [OAC 252:100-33]

G. Compliance Assurance Monitoring Requirements and Specifications until December 31, 2012, for Unit 4 and December 31, 2013, for Unit 5:[40 CFR Part 64]

Parameter	**Indicator No. 1**
Indicator	Opacity
Measurement Approach	Opacity shall be monitored using a continuous opacity monitor.
Indicator Range	An excursion is defined as an opacity greater than 20% except for one six-minute period per hour not to exceed 27% opacity. Excursions trigger an inspection, corrective actions, and a reporting requirement.
Data Representativeness Performance Criteria	The opacity monitoring system shall consist of a continuous opacity monitor which has been certified using the methods and procedures of 40 CFR Part 60, Appendix B, Performance Specification 1.
QA/QC Practices and Criteria	Filter (attenuator) audit conducted at least once annually.
Monitoring Frequency	Opacity is monitored at least once every 15 seconds
Data Collection Procedure	Data are recorded by Continuous Parameter Monitoring System (CPMS) or Data Acquisition Handling System computer
Averaging Period	Six-minute averages

H. Compliance Assurance Monitoring Requirements and Specifications, beginning January 1, 2013, for Unit 4 and January 1, 2014, for Unit 5. [40 CFR Part 64]

Parameter	**Indicator No. 1**
Indicator	ESP power level
Measurement Approach	Voltage and amperage monitoring
Indicator Range	Unit 4: An excursion is defined as total ESP power (3-hour average) outside of the range of 768 to 2,697 kW. Unit 5: An excursion is defined as total ESP power (3-hour average) outside of the range of 734 to 2,482 kW. Excursions trigger an inspection, corrective actions, and a reporting requirement.
Data Representativeness Performance Criteria	The electrical voltage and amperage monitoring shall be installed and calibrated in accordance with manufacturer specifications.
QA/QC Practices and Criteria	Calibration and maintenance of the ESP electrical component monitoring shall be conducted per manufacturer specifications.
Monitoring Frequency	ESP power is monitored at least four times per hour.
Data Collection Procedure	Data are recorded by Continuous Parameter Monitoring System (CPMS) or Data Acquisition Handling System computer or manually.
Averaging Period	3-hour rolling averages

I. Each existing affected boiler shall install and operate the SIP-approved equipment no later than five years after EPA approval of the SIP incorporating the Best Available Retrofit Technology (BART) requirements or final resolution to any BART-related legal action, whichever is later.

J. Units 4 and 5 shall be equipped with Low-NOx burners and overfire air systems which reduce NOx emissions to the limits stated.

K. The permittee shall maintain the combustion controls (Low-NOx burners and overfire air systems) and establish procedures to ensure the controls are properly operated and maintained.

L. The facility shall comply with the 0.15 lb/MMBTU NOx and 0.37 lb/MMBTU CO (30-day rolling average) limitations within 180 days following installation of the Low-NOx burners and overfire air systems.

M. “Boiler operating day” shall have the same meaning as in 40 CFR Part 60, Subpart Da.

N. Compliance with the CO lb/MMBTU emission limits shall be determined on the basis of the average emission rate for a 30-day rolling average. [OAC 252:100-8-6]

O. Continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) for CO shall be installed and operated on each boiler. The monitoring systems shall be installed, operating, and certified within 180 days of commencement of operations of each boiler following installation of Low-NOx burners and overfire air systems. [OAC 252:100-43]

EUG 4 Permitted Boiler No. 6

EU ID#	Point ID#	EU Name/Model	Construction Date
4-B	01	Unit 6 Boiler, 5,150 MMBTUH, Combustion Engineering, S/N AA-B0001	1978

A. The above unit is subject to emissions limitations as follow: [OAC 252:100-8-5(d)]

Emission Unit	PM lb/hr	SO_2 lb/hr	NOx lb/hr	VOC lb/hr	CO lb/hr
4-B-01	212.00	6,180.0	3605.0	390.00	180.0

B. Boiler No. 6 shall have the following emission limitations:
[40 CFR 60.429(a)(1), 43(a)(2), and 44(a)(3)]

Emission Unit	**SO_2 lbs/MMBTU**	**NO_X lbs/MMBTU**	**PM lbs/MMBTU**	**Opacity* %**
4-B-01	1.2	0.7	0.10	20

* opacity shall be limited to 20% except for one six minute period per hour of not more than 27%. [40 CFR 60.42(a)(2)]

C. Boiler 6 (4-B-01) is subject to NSPS Subpart D and shall comply with all applicable requirements including those in Specific Condition 1. [OAC 252:100-4]

D. The permittee shall operate and maintain the continuous monitoring systems for Boiler 6 (4-B-01) using the applicable methods and procedures set forth and shall record the output of the systems. [40 CFR 60.45(a)]

E. Boiler 6 (4-B-01) is authorized to utilize coal as primary fuel and natural gas as startup fuel. [OAC 252:100-31]

F. Compliance with the SO_2 lb/MMBTU emission limits in Specific Condition 1 shall be determined on the basis of the average emission rate for three successive boiler operating hours, a 3-hour rolling average. [40 CFR 60.43]

G. Compliance with the NO_X lb/MMBTU emission limits shall be determined on the basis of the average emission rate for a 3-hour rolling average. [OAC 252:100-33]

H. Compliance Assurance Monitoring Requirements and Specifications, beginning January 1, 2012. [40 CFR Part 64]

Parameter	**Indicator No. 1**
Indicator	ESP power level
Measurement Approach	Voltage and amperage monitoring
Indicator Range	An excursion is defined as total ESP power (3-hour average) outside of the range of 651 to 1,325 kW. Excursions trigger an inspection, corrective actions, and a reporting requirement.
Data Representativeness Performance Criteria	The electrical voltage and amperage monitoring shall be installed and calibrated in accordance with manufacturer specifications.
QA/QC Practices and Criteria	Calibration and maintenance of the ESP electrical component monitoring shall be conducted per manufacturer specifications
Monitoring Frequency	ESP power is monitored at least four times per hour.
Data Collection Procedure	Data are recorded by Continuous Parameter Monitoring System (CPMS) or Data Acquisition Handling System computer or manually
Averaging Period	3-hour rolling averages

EUG 5 Coal Piles: The emissions are “grandfathered” and limited to the existing equipment as it is.

EU ID#	Point ID#	EU Name/Model	Construction Date
5-B	01	Coal Piles	1972

EUG 6A Coal Unloading and Processing: The emissions are “grandfathered” and limited to the existing equipment as it is.

EU ID#	Point ID#	EU Name/Model	Construction Date
6-B	01	Rotary Coal Car Dumper	1972
6-B	02	Radial Stacker from Car Dumper	1972
6-B	03	Reclaim Conveyor (Units 4 & 5)	1972

EUG 6B Coal Unloading & Processing: The following emissions units are subject to emissions limitations as shown.

EU ID#	Point ID#	EU Name/Model	PM_{10} Emissions	
			lb/hr	TPY
6-B	05	Tripper Gallery (Units 4 & 5)	0.01	0.06
6-B	07	Reclaim Conveyor (Unit 6)	0.01	0.06
6-B	10	Crusher (Unit 6)	0.01	0.06
6-B	11	Transfer Tower #3 (Unit 6)	0.01	0.06
6-B	12	Surge Bin (Unit 6)	0.22	0.24
6-B	13	Tripper Gallery	0.22	0.24
6-B	06	Linear Stacker (Unit 6)	0.75	3.30
6-B	08	Transfer Tower #1 (Unit 6)	0.03	0.14
6-B	09	Transfer Tower #2 (Unit 6)	0.03	0.14
6-B	04	Crusher (Units 4 & 5)	6.60	14.45

A. The owner or operator shall comply with all applicable NSPS Subpart Y requirements of 40 CFR Part 60 for coal processing equipment serving Unit 6 which was constructed, reconstructed, or modified after October 24, 1974.
[OAC 252:100-4 and 40 CFR 60.250 to 60.254]

B. Operations 6-B-08, 6-B-09, 6-B-10, 11 shall vent exhausts to fabric filters or equivalent devices with at least 99% control efficiency for PM. [OAC 252:100-8-6(a)]

C. Operations 6-B-12 and 6-B-13 shall vent exhausts to water droplet injection with mist eliminators or equivalent devices with at least 97% control efficiency for PM.
[OAC 252:100-8-6(a)]

D. The permittee shall apply water or foam to coal in Operation 6-B-07 and 6-B-04 when crushing or handling coal to control fugitive dust emissions.

[OAC 252:100-25 and 40 CFR 60.252(c)]

E. The permittee shall conduct Method 9 or Method 22 visual observations of emissions from the discharges from each of the above units during at least one daylight unloading/ crushing event per week. In no case shall the observation period be less than six minutes in duration. If any emission unit has not operated during daylight hours for the week, this shall be noted on the log, and the visible emission observation for that unit will not be required. For each unit, when four consecutive weekly visual observations each show accumulated emission times of less than 6 minutes, the frequency of observations may be reduced to monthly. If visible emissions are observed for six minutes in duration for any observation period and such emissions are not the result of a malfunction, then the permittee shall conduct, for the identified points, during the same unloading event or the next daylight unloading event, a visual observation of emissions, in accordance with 40 CFR Part 60, Appendix A, Method 9.

i. If the Method 9 observations, triggered above, shows no visible emissions, or no emissions of a shade or density greater than twenty (20) percent equivalent opacity, compliance is demonstrated, no further action is required, and the frequency may be reduced to weekly Method 22 visual observations, as above. If the Method 9 observation, triggered above, show emissions of a shade or density greater than twenty (20) percent equivalent opacity, a Method 9 observation shall be conducted once per daylight unloading event until compliance is demonstrated. Once compliance is demonstrated, no further action is required and the frequency may revert back to weekly Method 22 visible observations. Upon any showing of non-compliance the observation frequency shall revert to once per daylight unloading event.

ii. If more than one six-minute Method 9 observation exceeds 20% opacity in any consecutive 60 minutes; or more than three six-minute Method 9 observations in any consecutive 24 hours exceeds 20% opacity; or if any six-minute Method 9 observation exceeds 60% opacity; the owner or operator shall comply with the provisions for excess emissions of OAC 252:100-9. [OAC 252:100-25]

F. Within 180 days of commencement of operations of the new controls on Units 6-B 12 and 6-B 13, the permittee shall conduct performance testing as required by 40 CFR Part 60, Subpart Y, and submit a written report documenting compliance with applicable standards for PM/opacity. [40 CFR 60.8]

EUG 7 Flyash Storage: The following emissions unit is considered insignificant since emissions are less than 5 TPY of any pollutant.

EU ID#	Point ID#	EU Name/Model	Construction Date
7-B	01	Fly Ash Silo	1972
7-B	02	Fly Ash Silo	1972
7-B	03	Fly Ash Silo	1982
7-B	04	Fly Ash Silo	1978

EUG 8 Liquid Fuel Storage: The following emissions units are considered insignificant since emissions are less than 5 TPY of any pollutant.

EU ID#	Point ID#	EU Name/Model	Capacity (Gallons)	Construction Date
8-B	01	Gasoline	2,000	1993
8-B	02	Diesel (machine shop)	8,300	2003
8-3	03	Diesel (heavy equipment)	7,500	1979
8-B	04	Diesel (heavy equipment)	10,000	1976
8-B	05	Diesel (Unit 3 auxiliary generator)	750	1970
8-B	06	Diesel (Unit 3 fire pump)	200	1997
8-B	07	Diesel (Unit 4 fire pump)	300	1997
8-B	08	Diesel (Unit 6 auxiliary generator)	400	1978
8-B	09	Diesel (Unit 4 auxiliary generator)	500	1976
8-B	10	Diesel (Unit 5 auxiliary generator)	500	1976
8-B	11	Liquid fuel day tank	40,000	1956

EUG 9 Insignificant Engines: The following emissions units are considered insignificant.

EU ID#	Point ID#	EU Name/Model	Serial Number	Capacity (HP)	Construction Date
9-B	01	Detroit Diesel Model 5117982	12VA-11595	710	1970
9-B	03	Cummins Model NT855-F2	10946353	340	1979
9-B	05	Waukesha Model F-2896	288522	710	1976
9-B	04	Waukesha Model F-2896 DSIM	288523	710	1976
9-B	06	Detroit Diesel Model 81637300	16VF002836	710	1978

A. Upon the compliance date for existing engines at a major source of HAP, the owner/operator shall comply with all applicable requirements of the NESHAP: Reciprocating Internal Combustion Engines, Subpart ZZZZ, for each affected facility including but not limited to: [40 CFR 63.6580 through 63.6675]

<u>What This Subpart Covers</u>

i. § 63.6580 What is the purpose of subpart ZZZZ?
ii. § 63.6585 Am I subject to this subpart?
iii. § 63.6590 What parts of my plant does this subpart cover?
iv. § 63.6595 When do I have to comply with this subpart?

<u>Emission and Operating Limitations</u>

v. § 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

<u>General Compliance Requirements</u>

vi. § 63.6605 What are my general requirements for complying with this subpart?

<u>Testing and Initial Compliance Requirements</u>

vii. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
viii. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

<u>Continuous Compliance Requirements</u>

ix. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

<u>Notifications, Reports, and Records</u>

x. § 63.6650 What reports must I submit and when?
xi. § 63.6655 What records must I keep?
xii. § 63.6660 In what form and how long must I keep my records?

<u>Other Requirements and Information</u>

xiii. § 63.6665 What parts of the General Provisions apply to me?
xiv. § 63.6670 Who implements and enforces this subpart?
xv. § 63.6675 What definitions apply to this subpart?

EUG 10 New Fire Pump Engine

EU ID#	Point ID#	EU Name/Model	Serial Number	Capacity (HP)	Construction Date
10-B	01	Cummins CFP6E	46715829	225	2007

A. Engine 10-B-01 shall have the following emissions limitations.

Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
10-B-01	0.20	0.01	0.01	0.01	3.87	0.19	3.87	0.19	1.73	0.09

B. Engine 10-B-01 is subject to NSPS Subpart IIII and shall comply with all applicable requirements. [40 CFR 60.4200 – 4219]

C. Operation of engine is limited to 100 hours per year non-emergency usage. There is no limit on emergency usage.

EUG 11 New Emergency Generator

EU ID#	Point ID#	EU Name/Model	Serial Number	Capacity (HP)	Construction Date
11-B	01	Generac Model 005887-0	NA	25 (20-kW)	2010

A. Engine 11-B-01 is subject to 40 CFR Part 60, Subpart JJJJ, and shall comply with all applicable standards for owners or operators of stationary spark ignition internal combustion engines:

i. 60.4230: Am I subject to this subpart?
ii. 60.4231: What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines?
iii. 60.4232: How long must my engines meet the emissions standards if I am a manufacturer of stationary SI internal combustion engines?
iv. 60.4233: What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?
v. 60.4234: How long must I meet the emissions standards if I am an owner or operator of a stationary SI internal combustion engine?
vi. 60.4235: What fuel requirements must I meet if I am an owner or operator of a stationary SI internal combustion engine?
vii. 60.4236: What is the deadline for importing or installing stationary SI ICE produced in the previous model year?
viii. 60.4237: What are the monitoring requirements if I am an owner or operator of a stationary SI internal combustion engine?
ix. 60.4238: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\leq$ 19 KW (25 HP).
x. 60.4239: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\geq$ 19 KW (25 HP) that use gasoline?

xi. 60.4240: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\geq$ 19 KW (25 HP) that use LPG?
xii. 60.4241: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program?
xiii. 60.4242: What other requirement must I meet if I am a manufacturer of stationary SI internal combustion engines?
xiv. 60.4243: What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?
xv. 60.4244: What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?
xvi. 60.4245: What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?
xvii. 60.4246: What parts of the General Provisions apply to me?
xviii. 60.4247: What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines?
xix. 60.4248: What definitions apply to this subpart?

2. Boilers 4, 5, and 6 (3-B-01, 3-B-02, and 4-B-01) are authorized to combust non-hazardous waste, on an as-needed basis, generated on-site, from other OG&E facilities, or from OG&E employees and retired employees.

A. The waste combusted may include, but is not limited to, wastewater treatment sludge, used oil-dry, used oil, used solvent, used anti-freeze, boiler cleaning solution (EDTA), activated carbon, demineralizer resin, slop oil and ash collected from oil combustion. [OAC 252:100-31]
B. Emissions of mercury from water treatment sludge combustion shall not exceed 3,200 grams per day. The permittee may demonstrate, using the approved methods, that mercury present in sludge does not equal 3,200 grams per day. [40 CFR 61.52(b)]
C. Prior to burning any waste water treatment sludge, the permittee shall conduct testing of the mercury content of water treatment sludges. Testing shall be conducted using either Method 105 of 40 CFR 61 Appendix B, or by Method 7471A of SW-846, "Test Methods for Evaluating Solid Waste" as approved by EPA on September 28, 2000. [40 CFR 61.54(a) and 40 CFR 60.13(h)]

3. Upon issuance of an operating permit, the permittee shall be authorized to operate the facility continuously (24 hours per day, every day of the year). [OAC 252:8-6(a)]

4. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements including the following: [40 CFR Part 75]

A. SO_2 allowances and NOx 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.

5. The records of operations shall be maintained on-site for at least five years after the date of recording and shall be provided to regulatory personnel upon request. Required records may be kept in digital format. [OAC 252:8-6(a)(3)(b)]

A. Acid Rain CEMS data and opacity monitor data for Units 4, 5 and 6.
B. Quantities of fuel and waste products burned by type (annual).
C. Amounts of wastewater treatment sludges and mercury content of those sludges for each event of sludge being burned.
D. Records as required by NSPS Subpart JJJJ for the new emergency generator, Engine 11-B-01.
E. Records as required by 40 CFR Part 63, Subpart ZZZZ, for the engines in EUG-9, upon the compliance date for existing emergency CI engines larger than 500-hp.
F. Records as required for the fugitive dust control compliance plan (Specific Condition No. 11).
G. Records of ESP operating powers, following implementation of monitoring of those parameters.
H. CO emissions records (30-day rolling averages).
I. Records of visible emissions testing for EUG-6B.
J. Records as required by OAC 252:100-8-36.2(c).

6. The following records shall be maintained on-site to verify insignificant activities. [OAC 252:8-6(a)(3)(b)]

A. Stationary reciprocating engines: number of hours operated for each generation engine in EUG No. 9 (monthly and calendar year).
B. Fuel storage/dispensing equipment: gasoline purchases for Tank 8-B-1 (monthly and calendar year).

7. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility.[OAC 252:100-8-6(d)(2)]

A. OAC 252:100-11 Alternative Emissions Reduction
B. OAC 252:100-15 Mobile Sources
C. OAC 252:100-23 Cotton Gins
D. OAC 252:100-24 Grain Elevators
E. OAC 252:100-39 Nonattainment Areas
F. OAC 252:100-47 Landfills

8. No later than 30 days after each anniversary date of the issuance of the original Title V operating permit (June 27, 2001), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit. [OAC 252:100-8-6 (c)(5)(A), (C) & (D)]

9. At least once during the term of the operating permit, the permittee shall conduct performance testing and submit a written report of results on the Boilers 4, 5, and 6.

A. Performance testing by the permittee shall use the following test methods specified in 40 CFR 60.

Method 1: Sample and Velocity Traverses for Stationary Sources.
Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4: Determination of Moisture in Stack Gases.
Method 201: Determination of PM Emissions from Stationary Sources
Method 202: Condensable Particulate Matter

B. A copy of the test plan shall be provided to AQD at least 30 days prior to each test date.
C. Performance testing shall be conducted while each boiler is operating within 10% of the rated capacity.
D. The testing reports shall include ash content of the coal being burned during testing.

10. The facility shall comply with the following fugitive dust control measures

A. Beginning October 14, 2012, except as provided, the facility shall not maintain its coal inventory in excess of 1,462,500 tons coal (approximately 75 days' supply) plus additional overage that is reasonable based on circumstances.

i. Such a reduction in the size and height of the coal pile depends on several factors including but not limited to operations at the facility and the ability of OG&E to manage its contracts with its coal suppliers and railroads to effectuate the desired outcome.
ii. Permittee will maintain information/data regarding factors beyond the control of the operator that necessitate additional coal being stored.
iii. Coal inventory may be determined as beginning inventory minus usages plus receipt.

B. Additional chemical/water spray equipment installed at the railcar unloading station will apply chemical/water to empty railcars prior to exiting facility property.

i. Permittee will observe and document chemical/water application in quarterly audits. Application will not be required during periods of freezing temperatures.

ii. If observations, as required in condition "F" below, show no benefit regarding reduction of fugitive dust emissions, documentation of the observation shall be submitted to AQD thirty days (30 days) prior to discontinuing use of the equipment.

C. Additional trees shall be planted as windbreaks along the [north] property boundary. The planting shall be conducted no later than May 31, 2011.
D. Daily records of coal pile watering activities shall be kept. Each day's records shall include either a description of watering activities or reasons why watering was not conducted (e.g., rain storms wet down coal piles without artificial watering being needed).
E. The operator shall conduct training for employees with responsibilities of watering the coal pile. This training shall include the process of documentation related to water truck activities. Documentation of employee training will be maintained on-site and made available for DEQ inspection upon request.
F. Quarterly self audits of fugitive dust control measures described above shall be conducted. The permittee shall have the discretion of maintaining records in digital format.

11. The permittee shall complete the following tasks at the Muskogee Station by the dates specified. The permittee shall reduce the percent of total time that opacity emissions are in excess of 20 percent to a level equal to or below the level specified in the following table:

[District Court Case Number CJ-2011-3361]

Implementation Date†	***Muskogee Station***
January 1, 2012	3.5%
January 1, 2013	1.0%*
January 1, 2015	1.0%**

*annual rolling average per station

**annual rolling average per unit

†Implementation Dates signify when the annual period will begin for calculating the annual rolling average. The annual rolling average rates listed in the table above shall be achieved within one year of the corresponding implementation date and shall include opacity emissions that occur at any time regardless of whether the boiler(s) are operating

12. The permittee shall complete the following tasks at the Muskogee Station by the dates specified: [District Court Case Number CJ-2011-3361]

Task Description	***Deadline***
Operation of ESPs while the units are offline consistent with procedures for safe operation of the ESPs.	January 1, 2013
Fabrication, installation, and operation of a cross-tie system from ash silo duct work of one unit to the ESP of another unit consistent with procedures for operation and maintenance of the cross-tie system.	January 1, 2013
Submit administratively complete permit applications to DEQ incorporating the two tasks listed above into the appropriate Title V operating permits.	January 1, 2013

The permittee will provide quarterly reports describing the measures implemented to address opacity during the previous quarter and the schedule for implementing any additional planned measures. These quarterly reports shall be submitted to DEQ within 30 days after the end of each calendar quarter.

13. The permittee shall apply for a modified operating permit within 180 days following commencement of operations of the Low-NOx burners and overfire air systems on either boiler.

Oklahoma Gas & Electric
Attn: Laura Herron, Environmental Administrator
P. O. Box 321
Oklahoma City, OK 73101

Re: Permit Application No. 2005-271-C (M-5)(PSD)
Muskogee Generating Station
Muskogee County, Oklahoma

Dear Ms. Herron:

Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to standard and specific conditions, that are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form 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 our office at (405) 702-4100.

Very truly yours,

David S. Schutz, P.E.
New Source Permits Section
AIR QUALITY DIVISION

Enclosure

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 No. 2005-271-C (M-5)(PSD)

Oklahoma Gas & Electric

having complied with the requirements of the law, is hereby granted permission to construct modifications to a coal-fired electric generation plant in Sections 21, 22, 27, and 28, T15N, R19E, Muskogee, Muskogee County, Oklahoma, subject to standard conditions dated July 21, 2009, and specific conditions, both attached.

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

Division Director, Air Quality Division **Date**

DEQ Form #100-890 **Revised 10/20/06**

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)

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(18) 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]