OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **June 9, 2008**

TO:	Phillip Fielder, P.E., Permits and Engineering Group Manager, Air Quality
THROUGH:	Kendall Stegmann, Environmental Programs Manager, Enforcement
THROUGH:	Phil Martin, P.E., Engineering Section
THROUGH:	Jian Yue, P.E., Engineering Section
THROUGH:	Peer Review
FROM:	Donna Lautzenhiser, E.I., New Source Permits Section
SUBJECT:	Evaluation of Permit Application No. **2005-037-C (M-2) PSD** Western Farmers Electric Cooperative Anadarko Power Plant (SIC 4911) NW/4 of Section 14, T7N, R10W, Caddo County Latitude: 35.082 Longitude: -98.222 Located 1 mile north of SH 62 and 7th Street in Anadarko

SECTION I. INTRODUCTION

The Anadarko Power Plant ("the facility") is owned and operated by Western Farmers Electric Cooperative (WFEC) under Permit No. 2005-037-TVR, issued July 11, 2005. WFEC proposes to construct and operate three natural gas-fired peaking electric generating units at the facility to meet anticipated future energy demand. To limit the facility's potential emissions of hazardous air pollutants to below major source thresholds following installation of the new units, WFEC has requested an enforceable limit on the hours of operation of the existing combined cycle gas turbines (EUs AN-UNIT4, AN-UNIT5, and AN-UNIT6).

The added power block will consist of three General Electric LM6000 Sprint™ simple cycle aeroderivative combustion turbine generators. Each of the turbines will have a maximum peak heat input rate of 462.7 million British thermal units per hour (MMBTUH). The new combustion turbines will fire only pipeline-quality natural gas and will be equipped with water injection. The proposed new units will each have a nominal electrical generating capacity of 50 MW. Actual unit capacity will be determined during detailed design of the plant and may be 5 to 10-MW higher or lower than the nominal value of 50 MW, depending on ambient condition ratings and final design.

The facility is included in the 28 source categories specified in the Prevention of Significant Deterioration (PSD) regulations as being considered a major stationary source if the potential emissions of a PSD pollutant exceed 100 tons per year, due to the existing boilers and turbines at the facility. The existing facility already exceeds the potential to emit PSD pollutants in excess of 100 tons per year. Emission increases associated with the addition of the proposed new units will exceed the PSD Significant Emission Rates for NO_x, CO, and PM_{10}. Therefore, the project is subject to PSD review. Full PSD review consists of the following:

A. Evaluation of ambient air quality in the area for each regulated pollutant for which the combustion turbine project will result in a significant net emissions increase;
B. Demonstration that emissions increases will not cause or contribute to an increase in ambient concentrations of pollutants exceeding the remaining available PSD increment and the National Ambient Air Quality Standards (NAAQS);
C. Assessment of any adverse impacts on soils, vegetation, visibility, and growth in the area; and
D. A Best Available Control Technology (BACT) analysis for each regulated pollutant for which the proposed combustion turbine project will result in a significant net emissions increase.

SECTION II. FACILITY DESCRIPTION

The facility generates wholesale electricity which is transmitted over WFEC's electrical distribution system. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma. The current facility consists of two natural gas fired high pressure boilers, a gas/oil fired high pressure boiler, three gas/oil fired combined cycle gas turbines, a fire pump diesel engine for emergency backup, and other sources which are considered insignificant or trivial. The three boilers are backup units that only operate when it is feasible, such as during peak demand. Two of the boilers have been idle since 1984. One boiler was replaced in 1997, and another was replaced in 1998.

The combined cycle units consist of three parallel lines of equipment. Each line includes a gas/oil fired turbine and a condensing-type steam turbine drive connected by tandem shafting to a single electrical generator. Exhaust gases from each turbine are used to heat separate waste heat steam generators (boilers). Exhaust gases from the steam generators then pass through separate stacks to the atmosphere.

The gas/oil fired turbines produce power in the form of electrical energy and supply preheated combustion gases to the heat recovery boilers. Each turbine draws in compressed ambient air which is used to ignite the gas/oil in the combustion chamber and is expanded through the turbine driving the generator. The heat recovery boilers then use an extended-fin tube construction to recover heat from the large volumes of exhaust gases. The condensate leaving the condenser is pumped into the feedwater heater-deaerator of each boiler. Steam extracted from the steam turbine, and heat extracted from the gas/oil fired turbine, exhaust by way of the extended fin-tube surfaces in the low pressure section and provide heat for the feedwater heater. These two sources heat the feedwater before it enters the economizer where heat is again extracted to heat the feedwater to approximately 5 degrees below the saturation temperature.

There are two operating scenarios for the existing facility. For Scenario I, the existing boilers and turbines will be fueled with commercial-grade natural gas. For Scenario II, the turbines will be fueled with fuel oil, and the boilers will be fueled with natural gas. Emission units (EUs) are arranged into Emission Unit Groups (EUGs) in the "Equipment" section. EUG 6 contains the units being added to the facility.

A simple-cycle combustion turbine plant, referred to as the GENCO plant (owned and operated by WFEC ENERGY CO, LLC) is located adjacent to the facility. The GENCO plant operates under its own Title V permit No. 2000-273-TV issued May 12, 2005. The GENCO plant contains two General Electric LM6000 Sprint™ simple cycle combustion turbines, one emergency generator, and a cooling tower. For air quality permitting purposes regarding the determination of "major source" status, emissions associated with the GENCO plant are included with the facility's emissions. Accordingly, overall facility emissions will include the GENCO plant emissions as described further in this memorandum.

This permit will authorize installation of three (3) General Electric LM6000 Sprint™ simple cycle combustion turbine generators at the facility. Incidental to this authorization, storage tank T-2 is being converted from a fuel oil storage tank to a water storage tank. Also, tanks T-8 and T-9 (two 298-bbl condensate tanks) have been removed and replaced with one 300-bbl condensate storage tank.

SECTION III. EQUIPMENT

EUG 1 Boilers

EU	Manufacturer	MMBTUH	MW	Serial #	Const. Date
AN-UNIT1R	Nebraska	223	15	A-3882	1998
AN-UNIT2R	Nebraska	223	15	A-3648	1997

EUG 2 Grandfathered Boiler

EU	Manufacturer	MMBTUH	MW	Serial #	Const. Date
AN-UNIT3	Riley Stoker	531	44	3333	1958

EUG 3 Combined Cycle Gas Turbines

EU	Manufacturer	MMBTUH	MW	Serial #	Const. Date
AN-UNIT4	General Electric	852	100	248851	1975
AN-UNIT5	General Electric	852	100	248852	1975
AN-UNIT6	General Electric	852	100	248853	1975

EUG 4 Internal Combustion Engine

EU	Make/Model	hp	Serial #	Const. Date
AN-ENG1	Cummings NT-855-F	309	10531247	1975

EUG 5 Tanks

EU	Point	Contents	Barrels	Gallons	Const. Date
Tanks	T-1	Fuel Oil No. 2	443	18,600	1951
	T-2	Water	22,619	950,000	1958
	T-3	Fuel Oil No. 2	109,524	4,600,000	1975
	T-4	Fuel Oil No. 2	109,524	4,600,000	1975
	T-5	Unleaded Gasoline (UST)	238	10,000	1977
	T-6	Unleaded Gasoline (UST)	238	10,000	1977
	T-7	Diesel Fuel (UST)	286	12,000	1977
	T-8	Condensate	300	12,600	2007
	T-10	Lube Oil	71	3,000	1975
	T-11	Mineral Oil	71	3,000	1975
	T-12	Mineral Oil	71	3,000	1975

EUG 6 Simple Cycle Combustion Turbines

EU	Manufacturer	MMBTUH	MW[A]	Serial #	Const. Date
AN-UNIT9	General Electric	462.7	50	Unknown	Est. 2008
AN-UNIT10	General Electric	462.7	50	Unknown	Est. 2008
AN-UNIT11	General Electric	462.7	50	Unknown	Est. 2008

[A]Actual unit capacity will be determined during detailed design of the plant and may be 5 to 10-MW higher or lower than the nominal value of 50-MW, depending on ambient condition ratings and final design.

Stack Parameters

EU	Height (feet)	Diameter (feet)	Flow (ACFM)	Temperature (°F)
AN-UNIT1R	51	4.4	60,405	390
AN-UNIT2R	51	4.4	60,405	390
AN-UNIT3	111	7.5	107,928	260
AN-UNIT4	80	14.9	350,530	325
AN-UNIT5	80	14.9	350,530	325
AN-UNIT6	80	14.9	350,530	325
AN-UNIT9	60	10	587,630[A]	803[A]
AN-UNIT10	60	10	587,630 [A]	803[A]
AN-UNIT11	60	10	587,630 [A]	803[A]

[A]Lowest flow and temperature at 100% load

SECTION IV. POTENTIAL EMISSIONS

Potential emissions are listed in the following emission tables and are based on continuous operation of EUs AN-UNIT3 through AN-UNIT6 and operation of EU AN-UNIT1R and AN-UNIT2R for a total of 5,800 hours. This leads to overestimating the emissions from the source due to the fact that the boilers are only operated during peak demand periods. Emissions from Scenario II are also overestimated due to the fact that fuel oil No. 2 is only used as an emergency backup fuel. The new turbines have only one scenario.

For Scenario I (Table 3), the boilers and combined cycle gas turbines are fired with natural gas. Potential emissions of NO_X, CO, VOC, and PM_{10} from EUs AN-UNIT1R and AN-UNIT2R are based on manufacturer's data for natural gas combustion (NO_X: 0.035 lb/MMBTU, CO: 0.15 lb/MMBTU, VOC: 0.004 lb/MMBTU; PM_{10}: 0.005 lb/MMBTU) and each unit operating a maximum of 2,900 hours per year. Potential emissions of SO_2 are based on AP-42 (3/98), Chapter 1.4, Table 1.4-2 and each unit operating a maximum of 2,900 hours per year. The existing permit allows operation of both units up to a combined total of 5,800 hours per year. Emission estimates for EU AN-UNIT3 fired with natural gas are based on continuous operation and AP-42 (2/98), Chapter 1.4, Tables 1.4-1 and 1.4-2.

Emission estimates of CO, VOC, PM_{10}, and SO_2 for the combined cycle gas turbines (EUs AN-UNIT4, AN-UNIT5, and AN-UNIT6) fired with natural gas are based on a total of 23,700 hours of operation per year for all three turbines combined and AP-42 (10/96), Chapter 3.1, Table 3.1-1. Emission estimates of NO_X for the combined cycle gas turbines fired with natural gas are based on stack testing conducted in September and October of 1999 (0.60 lb/MMBTU) and a total of 23,700 hours of operation per year for all three turbines combined. Although the stack testing identified different emission rates of NO_X for each unit, the maximum emission rate determined during the testing was used to conservatively estimate the total potential emissions from the turbines. However, the individual emission factors will be used for emission inventory reporting of actual emissions. Testing was not conducted at the maximum rating of the turbines but a linear relationship was shown between the heat input and emissions of NO_X. Therefore, the maximum emission factor for NO_X was extrapolated from the testing data.

For Scenario II (Table 4), the combined cycle gas turbines (EUs AN-UNIT4, AN-UNIT5, and AN-UNIT6) are fired with fuel oil No. 2, and the boilers (EUs AN-UNIT1R, AN-UNIT2R, and AN-UNIT3) are fired with natural gas. Emission estimates of CO, VOC, PM_{10}, and SO_2 for the combined cycle gas turbines fired with fuel oil No. 2 are based on a total of 23,700 hours of operation per year for all three turbines combined and AP-42 (10/96), Chapter 3.1, Table 3.1-1. The NO_X emissions from the combined cycle gas turbines are based on stack testing conducted at the facility in 1974 on EU AN-UNIT5 and a total of 23,700 hours of operation per year for all three turbines combined. Since distillate fuel oil is only used for emergencies, these emission factors have been determined to be sufficient. The maximum fuel oil sulfur content and maximum fuel oil firing rate are based on a maximum SO_2 emission rate for the combined cycle gas turbines. The fuel oil firing rate varies for each unit depending upon the fuel oil sulfur content and how many units are being fired with fuel oil, as shown in the table on the following page. The allowable fuel oil sulfur concentration for the different operating scenarios is shown in Table 1.

Table 1
Allowable Fuel Oil Sulfur Concentration for Different Operating Scenarios

Fuel Oil % Sulfur	Maximum Firing Rate When 3 Units Are Operating (gal/hr/unit)	Fuel Oil % Sulfur	Maximum Firing Rate When 2 Units Are Operating (gal/hr/unit)	Fuel Oil % Sulfur	Maximum Firing Rate For 1 Unit (gal/hr)
				0.340	1,000
				0.330	1,100
				0.320	1,200
				0.310	1,300
		0.185	1,000	**0.300**	1,400
		0.180	1,100	**0.290**	1,500
0.140	1,000	**0.175**	1,200	**0.280**	1,600
0.135	1,100	**0.170**	1,300	**0.275**	1,700
0.130	1,200	**0.165**	1,400	**0.270**	1,800
0.125	1,300	**0.160**	1,500	**0.265**	2,000
0.120	1,500	**0.155**	1,600	**0.260**	2,100
0.115	1,700	**0.150**	1,900	**0.255**	2,300
0.110	2,000	**0.145**	2,200	**0.250**	2,700
0.105	2,500	**0.140**	2,800	**0.245**	4,600
0.100	5,000	**0.135**	4,600	**0.240**	4,800
0.095	5,300	**0.130**	4,900	**0.235**	5,000
0.090	5,700	**0.125**	5,200	**0.230**	5,200
0.085	6,100	**0.120**	5,500	**0.225**	5,300
0.080	6,500	**0.115**	5,700	**0.220**	5,400
		0.110	6,000	**0.215**	5,600
		0.105	6,500	**0.210**	5,700
				0.205	5,900
				0.200	6,100
				0.195	6,200
				0.190	6,500

The proposed new simple cycle combustion turbines will only combust natural gas. The total emissions calculated under each of the above operating scenarios include emissions from the new turbines. Emissions from the GENCO plant turbines are also included in each operating scenario, although these turbines are subject to a separate Title V permit.

The proposed new LM6000 combustion turbines are limited to 2,500 hours of operation per year per turbine with 250 start-up/shut down events per year per turbine. One start-up/shut down event is equivalent to one start-up (0 to 25 percent load) plus one shut down (25 to 0 percent load). Potential emissions from the new LM6000 combustion turbines are presented in Table 2.

Table 2
Total EUG 6 Simple Cycle Combustion Turbine Emissions

Pollutant	Emissions (TPY)		
	3 Turbines[1]	Start-up/Shut down[2]	Total
NO_X	157.4	3.2	161
CO	245.5	2.8	248
VOC	8.4	0.1	9
SO_2	5.5	0.2	6
PM_{10}	15.0	0.3	15
H_2SO_4 Mist	0.85	0.02	0.87

[1]Based on 2,500 hours of operation per turbine
[2]Based on 250 start-up/shut down events per turbine

Emission estimates for the 309-hp Cummings diesel fired engine (EU AN-ENG1) are based on a maximum of 500 operating hours per year and AP-42 (1/95), Chapter 3.3, Table 3.3-2, for uncontrolled diesel engines. Brake-specific fuel consumption for the 309-hp engine is 7,000 BTU/hp-hr for a fuel consumption of 15.5 gallons of diesel per hour. Emissions from the engine will be below 5 TPY because the engine will be limited to 500 hours of operation per year (exclusive of emergency events).

Table 3
Facility-Wide Emissions Scenario I (Natural Gas)

	NO_X		CO		VOC		PM_{10}		SO_2	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Anadarko Power Plant										
AN-UNIT1R	7.8	11.3	33.5	48.5	0.9	1.3	1.1	1.6	0.1	0.2
AN-UNIT2R	7.8	11.3	33.5	48.5	0.9	1.3	1.1	1.6	0.1	0.2
AN-UNIT3	145.8	638.5	43.7	191.5	2.9	12.5	4.0	17.3	0.3	1.4
AN-UNIT4	580.0[1]	2,291	93.7	370.1	20.5	81.0	35.7	141.0	0.6	2.4
AN-UNIT5	580.0[1]	2,291	93.7	370.1	20.5	81.0	35.7	141.0	0.6	2.4
AN-UNIT6	580.0[1]	2,291	93.7	370.1	20.5	81.0	35.7	141.0	0.6	2.4
AN-ENG1	9.6	2.4	2.1	0.5	0.8	0.2	0.7	0.2	0.6	0.2
Tanks	---	---	---	---	0.2	0.7	---	---	---	---
ANADARKO TOTAL	**1,911**	**7,537**	**393.9**	**1,399**	**67.2**	**259**	**114.0**	**443.7**	**2.9**	**9.2**
New Combustion Turbine Project										
AN-UNIT9[2]	42.0	52.5	65.5	81.8	2.3	2.8	4.0	5.0	1.5	1.8
AN-UNIT10[2]	42.0	52.5	65.5	81.8	2.3	2.8	4.0	5.0	1.5	1.8
AN-UNIT11[2]	42.0	52.5	65.5	81.8	2.3	2.8	4.0	5.0	1.5	1.8
Start-up and Shut down Units 9-11	-	3.2	-	2.8	-	0.1	-	0.3	-	0.2
NEW PROJECT TOTAL	**126.0**	**160.7**	**196.5**	**248.2**	**6.9**	**8.5**	**12.0**	**15.3**	**4.5**	**5.6**
ANADARKO and NEW PROJECT TOTAL	**2,037**	**7,697**	**590**	**1,648**	**74**	**267**	**126**	**459**	**7**	**15**
GENCO Plant										
Turbine Unit 7	41	79.64	122.5	45.5	2.1	0.6	3	6	1.56	3.08
Turbine Unit 8	41	79.64	122.5	45.5	2.1	0.6	3	6	1.56	3.08
Emerg Gen.	7.42	1.86	1.19	0.3	0.22	0.06	0.4	0.1	2.68	0.67
Cooling Twr.	-	-	-	-	-	-	0.7	0.14	-	-
GENCO TOTAL	**89.42**	**161.14**	**246.19**	**91.3**	**4.42**	**1.26**	**7.1**	**12.24**	**5.8**	**6.83**
OVERALL TOTAL	**2,126**	**7,858**	**836**	**1,739**	**78**	**269**	**133**	**471**	**13**	**22**

1 Based on the December 1999 stack test results.
2 Natural gas combustion

Table 4
Facility-Wide Emissions Scenario II (Fuel Oil No. 2)

	NO_X		CO		VOC		PM_{10}		SO_2	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Anadarko Power Plant										
AN-UNIT1R	7.8	11.3	33.5	48.5	0.9	1.3	1.1	1.6	0.1	0.2
AN-UNIT2R	7.8	11.3	33.5	48.5	0.9	1.3	1.1	1.6	0.1	0.2
AN-UNIT3	145.8	638.5	43.7	191.5	2.9	12.5	4.0	17.3	0.3	1.4
AN-UNIT4	630.5	2,490	40.9	161.6	14.5	57.3	52.0	205.4	74.4	293.9
AN-UNIT5	630.5	2,490	40.9	161.6	14.5	57.3	52.0	205.4	74.4	293.9
AN-UNIT6	630.5	2,490	40.9	161.6	14.5	57.3	52.0	205.4	74.4	293.9
AN-ENG1	9.6	2.4	2.1	0.5	0.8	0.2	0.7	0.2	0.6	0.2
Tanks	---	---	---	---	0.15	0.65	---	---	---	---
ANADARKO TOTAL	**2,063**	**8,134**	**235.5**	**773.8**	**49.2**	**187.9**	**162.9**	**636.9**	**224.3**	**883.7**
New Combustion Turbine Project										
AN-UNIT9[1]	42.0	52.5	65.5	81.8	2.3	2.8	4.0	5.0	1.5	1.8
AN-UNIT10[1]	42.0	52.5	65.5	81.8	2.3	2.8	4.0	5.0	1.5	1.8
AN-UNIT11[1]	42.0	52.5	65.5	81.8	2.3	2.8	4.0	5.0	1.5	1.8
Start-up and Shut down Units 9-11	-	3.2	-	2.8	-	0.1	-	0.3	-	0.2
NEW PROJECT TOTAL	**126.0**	**160.7**	**196.5**	**248.2**	**6.9**	**8.5**	**12.0**	**15.3**	**4.5**	**5.6**
ANADARKO and NEW PROJECT TOTAL	**2,189**	**8,295**	**432**	**1,022**	**56**	**196**	**175**	**652**	**229**	**889**
GENCO Plant										
Turbine Unit 7	41	79.64	122.5	45.5	2.1	0.6	3	6	1.56	3.08
Turbine Unit 8	41	79.64	122.5	45.5	2.1	0.6	3	6	1.56	3.08
Emerg Gen.	7.42	1.86	1.19	0.3	0.22	0.06	0.4	0.1	2.68	0.67
Cooling Twr.	-	-	-	-	-	-	0.7	0.14	-	-
GENCO TOTAL	**89.42**	**161.14**	**246.19**	**91.3**	**4.42**	**1.26**	**7.1**	**12.24**	**5.8**	**6.83**
FACILITY TOTAL	**2,278**	**8,456**	**678**	**1,113**	**60**	**197**	**182**	**664**	**235**	**896**

1 Units will be limited to natural gas combustion.

The proposed new combustion turbines will have emissions of hazardous air pollutants (HAPs). Table 5 below displays the total HAPs from the new turbines. The existing boilers, turbines, and emergency engine at the facility also emit HAPs. Further, the existing turbines and emergency engine at the GENCO plant emit HAPs. Consistent with the previous permit for the facility, as well as Permit No. 2000-273-TV for the GENCO plant, the greatest emitted HAP is formaldehyde. Formaldehyde emissions were totaled and are displayed in Table 6. Emission estimates of HAPs are based on the following: boilers - AP-42, Section 1.4 (7/98); Combustion Turbines - AP-42, Section 3.1 (4/00); and Diesel Engines - AP-42, Section 3.3 (10/96).

Table 5
HAP Emissions from the Combustion Turbine Project

Pollutant	**Emission Factor (lb/MMBTU)**	**lb/hr (3 turbines)**	**TPY (3 turbines)**
1,3-Butadiene	4.30×10^{-7}	0.0006	0.0007
Acetaldehyde	4.00×10^{-5}	0.0555	0.0694
Acrolein	6.40×10^{-6}	0.0089	0.0111
Benzene	1.20×10^{-5}	0.0167	0.0208
Ethylbenzene	3.20×10^{-5}	0.0444	0.0555
Formaldehyde	7.10×10^{-4}	0.9856	1.2319
Naphthalene	1.30×10^{-6}	0.0018	0.0023
PAH	2.20×10^{-6}	0.0031	0.0038
Propylene Oxide	2.90×10^{-5}	0.0403	0.0503
Toluene	1.30×10^{-4}	0.1805	0.2256
Xylenes	6.40×10^{-5}	0.0888	0.1110
Total HAPs	-	**1.43**	**1.78**

Table 6
Formaldehyde Emissions from the Existing Anadarko Boilers, Turbines, and Fire Pump and the GENCO Turbines and Emergency Diesel Engine

			Factor	**Emissions**	
Sources	**# Units**	**MMBTUH**	**lb/MMBTU**	**lb/hr**	**TPY**
Nebraska Boilers[A]	2	223	7.35×10^{-5}	0.033	0.048
Riley Stoker Boiler	1	531	7.35×10^{-5}	0.039	0.171
GE Combined Cycle Turbines[B]	3	852	7.10×10^{-4}	1.815	7.168
Cummings Emergency Fire Pump Engine[C]	1	2.5	1.18×10^{-3}	0.003	0.001
New Simple Cycle Turbines[D]	3	462.7	7.10×10^{-4}	0.986	1.232
GENCO Combustion Turbines[E]	2	452	7.10×10^{-4}	0.642	1.284
GENCO Emerg. Eng.[C]	1	5.17	1.18×10^{-3}	0.006	0.002
Totals				**3.52**	**9.91**

[A] Units are limited to annual operation of 5,800 hours combined.
[B] Units are requested with this permit application to be limited to annual operation of 23,700 hours combined.
[C] Unit is limited to 500 hours of operation per year.
[D] Units will be limited to annual operation of 2,500 hours each.
[E] Units are limited to annual operation of 4,000 hours each.

SECTION V. PSD REVIEW

Table 7 shows the annual emission totals from Table 2 and compares them with PSD significance thresholds to determine whether any exceed the amount for which review is required.

Table 7
PSD Comparison (TPY)

Pollutant	NO_X	CO	VOC	SO_2	PM_{10}	H_2SO_4
Emissions	161	248	9	6	15	0.87
Threshold	40	100	40	40	15	7
Significant?	Y	Y	N	N	Y	N

As shown in Table 7, the proposed project will have emissions increases at or above the PSD significance levels for NO_x, CO, and PM_{10}, and these are reviewed below. Full PSD review of emissions consists of the following, and much of the PSD review is taken from the application verbatim, but modifications have been made at various points.

A. Determination of best available control technology (BACT).
B. Evaluation of existing air quality.
C. Evaluation of PSD Increment consumption.
D. Analysis of compliance with National Ambient Air Quality Standards (NAAQS).
E. Pre- and post-construction ambient monitoring.
F. Evaluation of source-related impacts on growth, soils, vegetation, visibility.
G. Evaluation of Class I area impacts.

Part A: Determination of Best Available Control Technology (BACT)

The pollutants subject to review under the PSD regulations, and for which a BACT analysis is required, include nitrogen oxides (NO_X), carbon monoxide (CO), and particulates less than or equal to 10 microns in diameter (PM_{10}). The BACT review follows the "top-down" approach recommended by the EPA, as shown by the following steps.

1. Identify all control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining control technologies by effectiveness.
4. Evaluate most effective controls and document results.
5. Select BACT.

The only emission units for which a BACT analysis is required are the proposed combustion turbines since these are the only sources in the project. Economic as well as energy and environmental impacts are considered in a BACT analysis. The EPA-required top down BACT approach must look not only at the most stringent emission control technology previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc. WFEC identified these technologies and emissions data through a review of 123 determinations found in EPA's

RACT/BACT/LAER Clearinghouse (RBLC), as well as EPA's NSR and CTC websites, recent DEQ BACT determinations for similar facilities, and vendor-supplied information.

Control technologies that were identified for controlling emissions from combustion turbines and their effective controlled emission levels are listed in Table 8.

Table 8
Summary of Feasible Control Technologies for the LM6000 Combustion Turbines

Pollutant	Control Technology	Expected Performance (ppm)	Feasibility	Comments
NOx	Dry Low-NOx Burners	25	Feasible	Either option is standard on aero-derivative combustion turbines
	Water Injection	25	Feasible	
	XONON™	N/A	Not Feasible	Testing is still underway. Only used on a 1.5 MW unit not operating continuously.
	SCONOx™	3	Feasible	-
	Selective Non-Catalytic Reduction	N/A	Not Feasible	Exhaust temperature is too low.
	Selective Catalytic Reduction	2.5 - 5	Feasible	Must use high temperature catalyst or dilution air to reduce exhaust temperature.
CO	Combustion Control	63 (75-100% load) 66 lb/hr (25-50% load)	Feasible	-
	SCONOx™	2	Feasible	-
	Oxidation Catalyst	2 to 5	Feasible	-
PM_{10}	Low Ash Fuel and Combustion Control	4 lb/hr	Feasible	

NO_x BACT Review

NO_X is primarily formed in combustion processes in two ways: 1) the combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_X); and 2) the oxidation of nitrogen contained in the fuel (fuel NO_X). Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is assumed that essentially all NO_X emissions from the turbines originate as thermal NO_X. The rate of formation of thermal NO_X is a function of residence time and free oxygen, and is exponential with peak flame temperature. NO_X control techniques are aimed at controlling one or more of these variables during combustion. These control techniques include the XONON™ system and dry low-NO_X burners. The XONON™ system uses a catalyst to keep the system temperatures lower while dry low-NO_X burners offer a staged combustion process, resulting in a lower peak flame temperature.

Other control methods utilize add-on control equipment to remove NO_X from the exhaust gas stream after its formation. The most common control techniques involve the injection of ammonia into the gas stream to reduce the NO_X to molecular nitrogen and water. Ammonia can either be injected into the system without the use of a catalyst [selective non-catalytic reduction (SNCR)] or with the use of a catalyst [selective catalytic reduction (SCR)]. Finally, a technology referred to as the SCONOx™ system relies upon a catalyst similar to SCR to reduce NO_X emissions, but does so without injecting ammonia into the exhaust gas stream.

The applicant has proposed water injection to achieve 25-ppmvd NO_X or less, adjusted to 15% oxygen as BACT.

SCONOx™ is an emerging catalytic and absorption technology that has shown some promise for turbine applications. Recently, the manufacturer of the SCONOx™ system has announced that it will no longer offer this control technology.

Catalytic Combustion (XONON™) The system controls NO_X emissions by preventing their formation. The key to the XONON™ system is the utilization of a chemical process versus a flame to combust fuel, thus limiting temperature and NO_X formation. The XONON™ system is an integral part of the combustor. The fuel and air that are supplied to the combustor are thoroughly mixed before entering the catalyst. The catalyst is responsible for combusting the fuel to release its energy. Due to the low catalyst operating temperatures, the nitrogen molecules are not involved in the reaction chemistry; they pass through the catalyst unchanged, thereby eliminating NO_X formation. The XONON™ system does have the same high outlet temperature, and some NO_X is formed in the post-combustion process. However, use of the technology has limited NO_X emissions to less than 2.5-ppm.

Currently, the XONON™ system has not had wide-scale application. It has been demonstrated on a 1.5 MW unit in California, with the unit operating in a base load capacity (24 hours a day, 7 days a week). Tests are underway to apply this technology to other types and sizes of turbines; however, testing data is currently unavailable. As the proposed combustion turbines are expected to experience repeated start-ups and shut downs, it is unclear how the changing loading conditions would affect the XONON™ system.

Selective Catalytic Reduction (SCR) is a post-combustion technology that employs ammonia in the presence of a catalyst to convert NO_X to nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_X decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, de-activation due to aging, ammonia slip emissions, and the design of the ammonia injection system.

SCR represents state-of-the-art controls for combined-cycle back end gas turbine NO_X removal; it has seen only limited use on simple-cycle combustion turbines (in areas subject to LAER and small aero-derivative turbines that are probably permitted for more fuel usage than the proposed LM6000 units for the combustion turbine project) as determined from the RBLC query. SCR technology is being permitted as LAER and BACT for combined-cycle turbines at 2.5 to 5-ppm NO_X. Conventional SCR uses a metal honeycomb or "foil" catalyst support structure and requires a heat recovery steam generator to drop flue gas temperatures to less than 600°F.

Because of the high exhaust temperature of a simple-cycle turbine, a conventional SCR system is not technically feasible. Instead, a high temperature "zeolite" based SCR system has recently been introduced for use on certain simple-cycle turbines. Zeolite is a sodium alumina silicate ceramic material with a design operating temperature of approximately 800 to 1,000°F. Only a few natural gas-fired installations were identified that use these high-temperature systems. Two have had major problems such as catastrophic catalyst failures; the third has not yet acquired a long enough history to sufficiently evaluate its operational effectiveness. Although vendors reported that they have catalysts that they believe will operate under the high temperature conditions, they did not identify many combustion turbines successfully operating with SCR under simple-cycle conditions.

SCR systems consist of an ammonia injection system and a catalytic reactor. Urea can be decomposed in an external reactor to form ammonia for use in a SCR. Unreacted ammonia may escape through to the exhaust gas. This is commonly called “ammonia slip.” It is estimated that ammonia slip from an SCR on this size of unit could be 10-ppm; this is considered to be an environmental impact. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine PM_{10} in the form of ammonium salts. In addition, the storing of the ammonia on-site is another environmental concern. SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as a hazardous waste. This typically requires either returning the material to the manufacturer for recycle and reuse or disposal in designated landfills.

An SCR system results in a loss of energy due to the pressure drop across the SCR catalyst. To compensate for the energy loss in the SCR system, additional natural gas is required to maintain the net energy output, which also results in some additional air pollutant emissions.

An economic analysis was conducted for an SCR at two different control levels: 2.5-ppm and 5-ppm NO_x levels. At the 2.5-ppm control level the capital cost would be $3,124,506 with a cost/ton of $15,528. At the 5.0-ppm control level the capital cost would be $4,028,290 with a cost/ton of $18,774. The costs per ton presented for these levels of control with an SCR were considered not economically feasible.

Dry Low NO_x Combustors (DLN) are currently available from most turbine manufacturers. This technology seeks to reduce combustion temperatures thereby reducing NO_x. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

DLN combustion is essentially free of carbon formation especially when gaseous fuels are used. The absence of carbon not only eliminates soot emission but also greatly reduces the amount of heat transferred to the combustor liner walls by radiation and the amount of air needed for liner wall cooling. More air is available for lowering the temperature of the combustion zone and improving the flow pattern in the combustor.

For aero-derivative combustion turbines, such as the LM6000 combustion turbines proposed for this project, DLN or water injection is standard on the turbines for NO_x control. Both types of NO_x control are guaranteed to control NO_x to 25-ppm. The turbines chosen for this project will have water injection to control NO_x emissions to 25-ppm; therefore, water injection is used as the baseline for the proposed combustion turbines.

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NO_x control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with NO_x, forming nitrogen and water. The success of this process in reducing NO_x emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700 °F to 2,000 °F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Outside the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x and the ammonia slip concentrations (ammonia discharge from the stack) will be very high. The LM6000's flue gases have an exhaust temperature of approximately 800 °F. Such a low temperature would require that additional fuel be combusted after the gases exit the turbine in order to raise the temperature to the levels that SNCR will operate. Combustion of the additional fuel would not only increase the NO_x emissions, but also all other criteria pollutants, especially CO. In addition, the added fuel used to raise the exhaust gas temperature will increase the annual operating costs for the facility. SNCR has not been applied to any combustion turbines according to the RBLC database. Because of the comparatively low exhaust temperatures, fuel and energy requirements, environmental implications, and economic considerations; SNCR was considered to be infeasible for application to the proposed combustion turbines.

Water or Steam Injection works to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel ratio of less than one.

Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increase in power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions may be increased slightly by water injection depending on the amount of water that is injected.

WFEC has selected water injection as BACT and proposes a NO_x BACT limit of 25-ppmvd at 15% O_2 for the turbines. Although the RBLC search mentioned earlier shows that multiple combustion turbines have installed SCR as BACT, there are no records in the RBLC of peaking units utilizing control technology more stringent than water injection (or DLN combustors) as BACT.

Water injection that achieves 25-ppmvd NO_x, or less, adjusted to 15% oxygen is determined and accepted as BACT for NO_x emissions.

CO BACT Review

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO emissions. A compromise is usually established where the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from gas turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Post-combustion control involves the use of catalytic oxidation; front-end control involves controlling the combustion process to suppress CO formation.

The technologies identified for reducing CO emissions from the proposed turbines are the SCONOx™ system, an oxidation catalyst, and combustion controls.

<u>SCONOx™</u> is an emerging catalytic and absorption technology that has shown some promise for turbine applications. Recently, the manufacturer of the SCONOx™ system has announced that it will no longer offer this control technology.

<u>Oxidation Catalysts</u> are a post-combustion technology which does not rely on the introduction of additional chemicals, such as ammonia with SCR, for a reaction to occur. The oxidation of CO to CO_2 utilizes excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. At higher temperatures, catalyst sintering may occur, potentially causing permanent damage to the catalyst. The addition of a catalyst bed onto the turbine exhaust will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities.

Two resultant levels of CO emissions from an oxidation catalyst were analyzed for economic feasibility: 2-ppm and 5-ppm. At the 2-ppm control level the capital cost would be $4,068,953 with a cost/ton of $9,013. At the 5-ppm control level the capital cost would be $3,824,798 with a cost/ton of $8,521. The cost for both levels of control is considered to be economically infeasible for BACT. In addition to cost, catalytic oxidation would lead to increased downtime for catalyst washing and would present hazardous waste concerns during catalyst disposal. As stated previously, an oxidation catalyst oxidizes CO to CO_2 which is released to the atmosphere. CO_2 is a greenhouse gas that may be contributing to global warming. Increasing CO_2 emissions could have a negative impact on the atmosphere. It is not known if reducing CO emissions but increasing CO_2 emissions would be environmentally prudent at this point.

Due to the high cost and concerns with downtime, hazardous material disposal, and increasing CO_2 emissions, catalytic oxidation is not selected as BACT for control of CO emissions from the turbines. An RBLC search of 123 analyses indicated that while there are entries in the RBLC of simple cycle turbines constructed with oxidation catalysts, these entries are either driven by LAER (which cannot be used to establish BACT) or are a case-by-case determination.

<u>Good Combustion Practices</u> include operational and incinerator design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

The standard technology for reducing CO emissions is to maintain "good combustion" through proper control and monitoring of the combustion process. A survey of the RBLC database indicated that no add-on controls have been required to control CO emissions from simple-cycle turbines in attainment areas, except for a couple of units. Several units list CO catalyst (oxidation catalyst) for CO emissions control; however, all of these are either located in a nonattainment area (LAER) or are operated enough hours that naturally have higher uncontrolled CO emissions thereby making CO catalyst economically feasible. The database indicated that good combustion practices were the chosen control strategy selected through the BACT process. CO emissions from the permitted facilities ranged from 2 to 203-ppm for natural gas operation. Aeroderivative turbines tend to have higher emissions than frame turbines, but the RBLC does not distinguish between the two, nor does it indicate how many of these turbines are peaking units. Only one of these indicated that it was a peaking unit (80 MW at 1,700 lb/hr emission of CO, or 16 times the emission level of CO for these units). The operator determined the cost of controls at $8,521 to $9,013 for controlling CO by oxidation catalyst. The cost of controlling CO is excessive for these aeroderivative peaking units.

Good combustion practices and design to 63-ppmdv corrected to 15% O_2 is determined and accepted as BACT for CO emissions.

PM_{10} BACT Review

PM_{10} emissions from natural gas combustion sources consist of inert contaminants in natural gas, of sulfates from fuel sulfur or mercaptan used as odorants, of dust drawn in from the ambient air, and of particulate of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions.

Post-combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas-fired turbines. Available control strategies include the use of low ash fuel, such as natural gas, and combustion controls.

There are no energy, environmental, or economic impacts associated with combustion controls; the use of low ash fuel is not an add-on control device.

Based on a review of 86 cases in EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, there are no BACT requirements for add-on particulate control requirement for natural gas-fired combustion turbines. Therefore, BACT for PM_{10} emissions from the combustion turbines is the use of a low ash fuel (natural gas) and efficient combustion. There are no adverse environmental or energy impacts associated with the control alternative. Additionally, the proposed turbines will be subject to NSPS Subpart KKKK, which contains no specific particulate emission limits.

Good combustion practices in combination with use of natural gas is determined and accepted as BACT for PM_{10} emissions.

Start-up and Shut-down BACT Analysis

Controls that may be used during normal operation are not available to control start-up and shut-down emissions. SCR and CO catalysts require a minimum operating temperature to control emissions (for the catalytic reactions to occur for removal of NO_x and CO). This temperature is not reached until approximately 25 percent load. In addition, the water injection used to control NO_x emissions does not start until around 20 percent load. Water injection at lower loads would effectively quench the flame altogether. CO control costs were excessive for continuous operations and would be even higher for periods of start-up and shut-down. Controls of CO for periods of start-up and shut-down may be rejected for economic reasons. Therefore, there are no technically feasible control technologies for start-up and shut down emissions from the combustion turbines.

Start-up and shut down emissions are listed for the combustion turbine, below.

Table 9
Start-up and Shut Down Emissions

Pollutant	Start-up/Shut Down Emissions[A]		
	1 Turbine (lb/yr)	1 Turbine (TPY)	3 Turbines (TPY)
NO_X	2,150.0	1.08	3.2
CO	1,850.0	0.93	2.8
PM_{10}	200.0	0.10	0.3

[A]One start-up/shut down event is equivalent to one start-up plus one shut down.
Based on 250 start-up/shut down events per turbine.

The turbine manufacturer would not guarantee in writing a time frame for start-up and shutdown. Emissions during start-up and shutdown were calculated assuming a 2-hour period but with a reasonable expectation that full pre-mixed operation can occur in a fraction of that time. In the absence of manufacturer guarantees, the permit will define "start-up" as being the first two hours of operation. **BACT for these periods is acceptable as no add-on controls.**

Part B: Evaluation of Existing Air Quality
&
Part C: Evaluation of PSD Increment Consumption.
&
Part D: Analysis of Compliance with National Ambient Air Quality Standards (NAAQS).

The net annual emission increase from the project is modeled in the Significance Analysis of the Class II Area. Class II is the default classification for land that has not been specifically designated in some other class. The maximum-modeled ground-level concentrations are then compared to the corresponding modeling and monitoring significance levels. The U.S. EPA requires that a Full Impact Analysis be conducted if the project emissions result in maximum predicted concentrations that exceed modeling significance levels (MSLs) (i.e., significant impacts). In addition, the permitting agency has the authority to exempt a project from pre-construction monitoring if the concentrations modeled in the Significance Analysis are less than monitoring de minimis concentrations.

Air quality impact analyses were conducted to determine if ambient impacts would be above the EPA defined modeling and monitoring significance levels. If impacts are above the modeling significance levels, a radius of impact is defined for the facility for each pollutant out to the farthest receptor at or above the significance levels. If a radius of impact is established for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required for the Class II area. Modeling conducted by the applicant and reviewed by the DEQ demonstrated that emissions from the facility did not exceed the PSD modeling significance levels.

Modeling Methodology

Modeling was conducted using AERMOD (version 07026) to determine if a significant impact area for each pollutant occurred. A Cartesian receptor grid was used in the modeling analysis. Receptors were placed at 50-meter intervals along the site fence line, beyond which receptor grids were defined. The following spacing between receptors was used: 100-meters out to two kilometers, 250-meters out to five kilometers, and 1,000-meters out to 10 kilometers.

Oklahoma Mesonet data was provided to the AQD courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University and The University of Oklahoma and supported by the taxpayers of Oklahoma. A combination of Oklahoma Mesonet data from Fort Cobb, Oklahoma, and Integrated Surface Hourly data from Hobart Municipal Airport, Oklahoma were used for surface meteorological data for years 2001 to 2005 for the modeling analysis. Upper air data from Norman, Oklahoma for years 2001 to 2005 were used for the modeling analysis. The meteorological data were pre-processed in AERMET using land-use/micromet parameters, i.e., albedo, Bowen ratio, and surface roughness provided by the Oklahoma DEQ. A summary of these parameters is provided below (Table 10).

Table 10
AERMET Land-Use Parameters

Property	Winter Dec-Jan-Feb	Spring Mar-Apr-May	Summer Jun-Jul-Aug	Autumn Sep-Oct-Nov
Albedo Values	0.34	0.16	0.19	0.19
Bowen Ratio Average Values	1.18	0.35	0.65	0.85
Surface Roughness Values	0.02	0.13	0.08	0.01

A downwash analysis was completed using EPA's BPIP-PRIME model. The BPIP-PRIME model provided direction-specific building dimensions to evaluate downwash conditions. The facility is located in a rural area and the only buildings that could potentially affect emissions from the combustion turbine project are the on-site structures.

The appropriate U.S. Geological Survey (USGS) 7.5-minute topographic maps (from electronic DEM data) were used as inputs to the AERMAP program to obtain the necessary receptor elevations for all grids in the model.

The turbines will normally be operated in the 25-100% load range except during start-up, shut down, and malfunctions. Emissions from the turbines were modeled at 100% load, 75% load, 50% load, and 25% load. The stack parameters used in the modeling analysis are shown in Table 11.

Table 11
Stack Parameters

Source	% Load	Height	Diameter	Temperature	Exhaust Velocity
Unit 9, Unit 10, Unit 11 (each turbine)	100	60 feet	10 feet	802.7 °F	124.7 ft/sec
	75	60 feet	10 feet	743.4 °F	107.0 ft/sec
	50	60 feet	10 feet	686.1 °F	89.9 ft/sec
	25	60 feet	10 feet	621.2 °F	63.3 ft/sec

Modeling Results

The modeling results shown in Table 12 are the highest resulting concentrations and show that the proposed turbines will not result in a significant impact on ambient air quality in the vicinity of the site.

Table 12
Significance Level Comparisons

Pollutant	Averaging Period	Year	Maximum Concentrations (μg/m^3)	Significance Levels (μg/m^3)
NO_2	Annual	2001	0.22	1
CO	8-hour	2005	65.10	500
	1-hour	2003	233.63	2000
PM_{10}	Annual	2001	0.06	1
	24-hour	2002	2.44	5

The modeling indicates added facility emissions will result in ambient concentrations below the significance levels and no area of impact is defined. Therefore, no additional modeling for Increment or NAAQS compliance is required.

Part E: Pre- and Post-construction Ambient Monitoring.

The predicted maximum ground-level concentrations of pollutants by air dispersion models have demonstrated that the ambient impacts of the facility are below the monitoring exemption levels. No pre-construction or post-construction ambient monitoring will be required. The maximum ambient impacts of the source and the monitoring exemption levels are shown in Table 13.

Table 13
Comparison of Modeled Impacts to Monitoring Exemption Levels

Pollutant	Monitoring Exemption Levels		Ambient Impacts	
	μg/m^3	Averaging Time	μg/m^3	Averaging Time
NO_2	14	annual	0.22	annual
CO	575	8-hour	65.10	8-hour
PM_{10}	10	24-hour	2.44	24-hour

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

Mobile Sources

Current EPA policy is to require an emissions analysis to include mobile sources. In this case, mobile source emissions are expected to be negligible. Few added employees will be needed. The fuel for the plant will arrive by pipeline rather than by vehicle.

Growth Impacts

A growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the facility and to estimate emissions resulting from that associated growth. Associated growth includes residential and commercial/industrial growth resulting from the new facility. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. Although it is possible that additional personnel may be employed to aid the operation and maintenance of these combustion turbines, additional growth from this project is expected to be minimal.

Soils and Vegetation

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

NO_2 may affect vegetation either by direct contact of NO_2 with the leaf surface or by solution in water drops, becoming nitric acid. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. The maximum predicted NO_2 pollutant concentrations from the proposed power plant additions are expected to be below the secondary NAAQS. As discussed in the separate dispersion modeling report, no significant adverse impact on soil and vegetation due to NO_2 emissions is anticipated due to the addition of the three proposed turbines.

At the levels of CO that occur in urban air, there are no detrimental effects on materials or plants. However, human health may be adversely affected at such levels. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. The maximum predicted CO pollutant concentrations from the proposed power plant are expected to be below the NAAQS. As discussed in the separate dispersion modeling report, no significant adverse impact on soil and vegetation due to CO emissions is anticipated due to the proposed project.

PM can be carried over long distances by the wind and settle on the ground. The effects of this deposition include depleting nutrients in soils, damaging sensitive forests and farm crops, and affecting ecosystem diversity. These effects are generally associated with the removal of large quantities of soils from ecosystems, not with the possible addition of smaller quantities of fine materials. The use of only natural gas fuel in the proposed combustion turbines ensures minimal PM emissions from the project.

Visibility Impairment
The project is not expected to produce any perceptible visibility impacts in the immediate vicinity of the plant. Given the limitation of 20% opacity of emissions, and a reasonable expectation that normal operation of the natural gas fired combustion turbines will result in essentially zero opacity, no local visibility impairment is anticipated.

Part G: Evaluation of Class I area impacts.

Federal Class I Areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective. These areas were established as part of the PSD regulations included in the 1977 Clean Air Act Amendments. Federal Class I Areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. Class I Modeling Significance Levels (MSLs) for certain criteria pollutants have been proposed by the EPA and Federal Land Managers (FLMs) in the Federal Register (July 23, 1996, 40 CFR 51). The lower values proposed by the FLMs are summarized in Table 14.

Table 14
Class I MSLs (Recommended)

Pollutant	Modeling Significance Level (μg/m^3)		
	Annual	24-hr	3-hr
SO_2	0.1	0.2	1.0
PM_{10}	0.2	0.3	-
NO_2	0.1	-	-

In addition to these MSLs, the Federal Land Managers' Air Quality Related Values Work Group (FLAG) has published a Phase I report that defines certain Air Quality Related Values (AQRVs) that must be addressed in a Class I air quality analysis. AQRV indicators typically identified by FLMs include visibility impairment and acidic deposition. Although the FLMs are also concerned about ozone affects on vegetation, there are currently no models available to predict the impact of emissions from a single source on ozone concentrations in Class I Areas. Therefore, the FLMs analyze the results of the visibility and deposition analysis to gauge the impact of NO_X emissions from a facility on Class I Areas. If the results of the visibility and deposition analysis are acceptable, it is a good indicator that NO_X emissions from the facility will not adversely impact ozone concentrations in the Class I Areas.

The nearest Class I area to the facility is the Wichita Mountains Wilderness in southwestern Oklahoma. The Wichita Mountains Wilderness is approximately 43 km from the facility. The maximum total emissions of the pollutants that contribute to visibility impairment are less than ten times the distance to the Wichita Mountains Wilderness or 430 tons per year. Using the proposed Federal Land Managers' Air Quality Related Values Work Group (FLAG) guidance, Class I visibility and PSD Class I Increment analyses are not required.

SECTION VI. 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 for the combustion turbine project. Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration, Emission 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 have been submitted and fees paid for the past years.

OAC 252:100-8 (Permits for Part 70 Sources) [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. The project is a significant modification to the facility and requires that an application for modification of the Title V (Part 70) operating permit be submitted within 180 days of commencement of operation of the new units. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or 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 HAP 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 construction permit application, or developed from the applicable requirement.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner or operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. In addition, if the owner or operator wishes to be considered for the exemption established in

252:100-9-3.3, a Demonstration of Cause must be submitted within 30 calendar days after the occurrence has ended.

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]
Subchapter 19 regulates emissions of particulate matter from fuel-burning equipment. Particulate emission limits are based on maximum design heat input rating. Fuel-burning equipment is defined in §19-1.1 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. Thus, the turbines are subject to the requirements of this subchapter, and the emission factors identified in Section IV above demonstrate compliance. Applicability of this subchapter to existing equipment is unchanged by this project.

Equipment	PM Emission Limit	Potential PM Emissions
Turbines (3)	0.24 lbs/MMBTU	0.023 lb/MMBTU

OAC 252:100-25 (Smoke, 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. The turbines will remain compliant with this rule by using good combustion practices and utilizing pipeline-quality natural gas as fuel. Applicability of this subchapter to existing equipment is unchanged by this project.

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. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input averaged over 3 hours. For fuel gas having a gross calorific value of 1,000 BTU/SCF, this limit corresponds to fuel sulfur content of 1,203-ppmv. The permit requires the use of gaseous fuel with sulfur content less than 343-ppmv to ensure compliance with Subchapter 31 except for the emergency diesel engine. For that engine, the new equipment standard for emissions of oxides of sulfur measured as sulfur dioxide from oil-fired fuel-burning equipment is 0.8 pounds per MMBTU heat input, maximum three-hour average. AP-42 (10/96), Table 3.3-1, lists diesel fuel SO_2 emissions to be about 0.29 lb/MMBTU, which is in compliance.
Part 5 also requires an opacity monitor and sulfur dioxide monitor for equipment rated above 250 MMBTUH. Since the turbines are limited to natural gas only, they are exempt from the opacity

monitor requirement. Equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitor requirement. Based on the pipeline-quality natural gas requirement, the turbines will be exempt from the sulfur dioxide monitoring requirement. Applicability of this subchapter to existing equipment is unchanged by this project.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
NO_X emissions are limited to 0.20 lb/MMBTU, three-hour average, from all new gas-fired fuel-burning equipment with a rated heat input of 50 MMBTUH or greater. The three new simple cycle gas turbines (AN-UNIT7, AN-UNIT8, and AN-UNIT9) are subject to this requirement. Emissions of NO_X from the new turbines is 0.09 lb/MMBTU, which is in compliance with this subchapter. Applicability of this subchapter to existing equipment is unchanged by this project.

OAC 252:100-37 (Volatile Organic Compounds) [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. There are no storage tanks planned for this project.
Part 3 requires VOC loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling of tank trucks or trailers if the capacity of the vehicle is greater than 200 gallons. This facility does not have the physical equipment (loading arm and pump) to conduct this type of loading and is not subject to this requirement.
Part 5 limits the VOC content of coatings from any coating line or other coating operation. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize VOC emissions. Temperature and available air must be sufficient to provide essentially complete combustion.
Part 7 requires all effluent water separators openings or floating roofs to be sealed or equipped with an organic vapor recovery system. There are no effluent water separators located at this facility.
Part 7 also requires all reciprocating pumps and compressors handling VOC to be equipped with packing glands that are properly installed and maintained in good working order and rotating pumps and compressors handling VOC to be equipped with mechanical seals.
Applicability of this subchapter to existing equipment is unchanged by this project.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
Part 5 of OAC 252:100-41 was superseded by this chapter. 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 Area of Concern (AOC) has been designated anywhere in the state, 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 252:100-7	Permits for Minor Sources	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
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 Equipment	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-35	Carbon Monoxide	not type of emission unit
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Municipal Solid Waste Landfills	not in area category

SECTION VII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
The facility is a listed source as a fossil fuel-fired electric plan of more than 250 MMBTUH heat input with emissions greater than 100 TPY. PSD review was discussed in Section V.

NSPS, 40 CFR Part 60 [Subparts A and KKKK Applicable]
Subpart A requires the submittal of several notifications for NSPS-affected facilities. Within 30 days after starting construction or modification of any affected facility, the Facility must notify DEQ that construction has commenced. A notification of the actual date of initial start-up of any affected facility shall be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial start-up of the facility. The facility must notify DEQ at least 30 days prior to any initial performance test and must submit the results of the initial performance tests to DEQ.
Subpart KKKK, Stationary Combustion Turbines affects stationary combustion turbines constructed after February 18, 2005 with a heat input equal to or greater than 10.7 gigajoules per hour (10 MMBTUH) based on the higher heating value (HHV) of the fuel. The turbines must satisfy the NO_X standard set forth in §60.4320 and the SO_2 standard set forth in §60.4330. Monitoring of operations are set forth in §60.4335 and §60.4365 and test methods and procedures are set forth in §60.4405 and §60.4415.

Stationary combustion turbines regulated under this subpart are exempt form the requirements of subpart GG of this part.

NESHAP, 40 CFR Part 61 [Not Applicable]
The current project does not affect the applicability of subparts addressed in the existing operating permit.

There are no emissions other than trace amounts of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, coke oven emissions, mercury, radionuclides or vinyl chloride.

NESHAP, 40 CFR Part 63 [Not Applicable]
Only those subparts affected by the current project are addressed. At the time of last renewal, there were no affected subparts at the existing facility.
<u>Subpart YYYY</u>, Combustion Turbines. This subpart was promulgated on March 5, 2004, and affects combustion gas turbines that are located at major sources. Emission calculations have shown this facility to be a minor source of HAP.

CAM, 40 CFR Part 64 [Not Applicable]
Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source that is required to obtain a Title V 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

Applicability of this subchapter to existing equipment is unchanged by this project.

New turbines use a control device to meet an applicable emission limit and have the potential to emit greater than major source levels. However, the turbines are subject to a continuous monitoring requirement under the Acid Rain Program and are exempt from this part.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
The current project does not affect the applicability of subparts addressed in the existing operating permit. The turbines burn natural gas only. Natural gas is a listed substance in CAAA 90 Section 112(r). However, this substance is not stored on-site. The small quantity that is in the pipelines on the facility is much less than the 10,000-pound threshold and is excluded from all requirements including the Risk Management Plan.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
The facility submitted a Phase II Monitoring Plan on December 15, 1995, and subsequently submitted a revised application on March 1, 1996. EPA issued a certificate of approval for the Continuous Emission Monitoring System (CEM) for EU AN-UNIT3 in March 1999. A separate Acid Rain Permit, No. 97-059-AR, was issued on April 15, 1999. The acid rain renewal permit, Permit No. 2004-189-ARR, was issued on November 23, 2004. The Acid Rain permit contained all of the Acid Rain requirements for EU AN-UNIT3. EUs AN-UNIT1 and AN-UNIT2 serve generators with a nameplate capacity below the threshold level of 25 MWe and are therefore exempt from these requirements.

This project is an affected source since the new simple cycle turbines will commence operation after November 15, 1990, and they will serve generators with a nameplate capacity above the 25-MW threshold. The facility must submit an Acid Rain permit application in accordance with the requirements in 40 CFR 72.30. Paragraph 72.30(b)(2)(ii) requires a new source to submit an application for an Acid Rain permit at least 24 months prior to the start of operations. However, Mr. Dwight Alpern, HQ U.S. EPA, (202) 564-9651, has previously relayed that this requirement under Paragraph 72.30(b)(2)(ii) was for the benefit of the regulating agency (Oklahoma DEQ) which could and has waived this timing requirement. After startup the applicant shall apply for an Acid Rain permit to include the new sources.

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

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
EUs AN-UNIT1 and AN-UNIT2 serve generators with a nameplate capacity below the threshold level of 25 MWe and are therefore exempt from these requirements. EUs AN-UNIT4, AN-UNIT5, and AN-UNIT6 are combined cycle gas turbines and do not meet the definition of an affected unit under the Acid Rain Program. EU AN-UNIT3 is an affected unit and must meet the monitoring requirements of the Acid Rain Program whenever it is operated (typically only one week per year for preventative maintenance and testing purposes). EUs AN-UNIT7, AN-UNIT8, AN-UNIT9 are simple cycle gas turbines with a nominal electrical generating capacity of 50 MW meet the definition of an affected unit under the Acid Rain Program.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
Applicability of this subchapter to existing equipment is unchanged by this project.
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.

Conditions are included in the standard conditions of the permit to 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 VIII. 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 to a Part 70 source.

The applicant published the "Notice of Filing a Tier II Application" in *The Anadarko Public News*, a daily newspaper, in Caddo County on March 21, 2008. The notice stated that the application was available for public review at the Anadarko Public Library located at 215 West Broadway Anadarko, Oklahoma and was also available for review at the Air Quality Division main office. Upon completion of the draft permit, the applicant published a "Notice of a Tier II Draft Permit" in *The Anadarko Daily News*, a local newspaper. The draft of this permit was made available for public review for a period of 30 days. In addition, a copy of the draft permit is available at the AQD office in Oklahoma City, and on the Air Quality section of the DEQ web page at *www.deq.state.ok.us*. This site is not within 50 miles of another states border.

The facility requested concurrent public and 45-day EPA review of the draft permit and it was granted. No comments were received from the public or EPA.

The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

Fees Paid

Modification of a major stationary source construction permit fee of $1,500.

SECTION IX. SUMMARY

The operator has demonstrated the ability to achieve compliance with the requirements of the several air pollution control rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues concerning this facility. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Western Farmers Electric Cooperative **Permit Number 2005-037-C(M-2) PSD**
Anadarko Power Plant: Addition of Three Combustion Turbines

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on February 1, 2008. The Evaluation Memorandum, dated June 9, 2008 explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Points of emissions and emission limitations. [OAC 252:100-8-6(a)]

Equipment and emissions authorized under existing operating permit 2005-037-TVR for EUG 1, EUG 2, EUG 4, EUG 5, and Insignificant Activities, are not altered by this construction permit and remain as stated in the existing permit. Regarding EUG 3, the following limitations shall supercede those specified in Permit No. 2005-037-TVR.

EUG 3: Combined Cycle Combustion Turbines
Emission and operating limitations applicable to emission units (EUs) AN-UNIT4, AN-UNIT5, and AN-UNIT6 as specified in Specific Condition 1, EUG 3 of Permit No. 2005-037-TVR are hereby amended to require the following:

Scenario I (Natural Gas)

Permitted Emissions										
	NO_X		**CO**		**VOC**		**PM_{10}**		**SO_2**	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
AN-UNIT4	580.0	2,291	93.7	370.1	20.5	81.0	35.7	141.0	0.6	2.4
AN-UNIT5	580.0	2,291	93.7	370.1	20.5	81.0	35.7	141.0	0.6	2.4
AN-UNIT6	580.0	2,291	93.7	370.1	20.5	81.0	35.7	141.0	0.6	2.4

Scenario II (Fuel Oil No. 2)

Permitted Emissions										
	NO_X		**CO**		**VOC**		**PM_{10}**		**SO_2**	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
AN-UNIT4	630.5	2,490	40.90	161.6	14.5	57.3	52.0	205.4	74.4	293.9
AN-UNIT5	630.5	2,490	40.90	161.6	14.5	57.3	52.0	205.4	74.4	293.9
AN-UNIT6	630.5	2,490	40.90	161.6	14.5	57.3	52.0	205.4	74.4	293.9

A. Operation of EUs AN-UNIT4, AN-UNIT5, and AN-UNIT6 shall be limited to 23,700 hours combined per 12-month period.
B. The permittee shall conduct daily visual observations of the opacity from the exhausts associated with all emission units while burning fuel oil No. 2 and keep a record of these

observations. If visible emissions are detected, then the permittee shall conduct a thirty-minute opacity reading in accordance with EPA Reference Method No. 9.

[OAC 252:100-43]

C. EUs AN-UNIT4, AN-UNIT5, and AN-UNIT6 shall be fueled with commercial-grade natural gas. Under Scenario II, the fuel burning equipment shall use fuel oil up to the approved maximum firing rates and fuel oil sulfur content. [OAC 252:100-31]

D. EU AN-UNIT4, AN-UNIT5, and AN-UNIT6 shall not exceed the following fuel oil firing rates based on the fuel oil sulfur content and the number of units being fired with fuel oil.

Fuel Oil % Sulfur	**Maximum Firing Rate When 3 Units Are Operating (gal/hr/unit)**	**Fuel Oil % Sulfur**	**Maximum Firing Rate When 2 Units Are Operating (gal/hr/unit)**	**Fuel Oil % Sulfur**	**Maximum Firing Rate For 1 Unit (gal/hr)**
				0.340	1,000
				0.330	1,100
				0.320	1,200
				0.310	1,300
		0.185	1,000	**0.300**	1,400
		0.180	1,100	**0.290**	1,500
0.140	1,000	**0.175**	1,200	**0.280**	1,600
0.135	1,100	**0.170**	1,300	**0.275**	1,700
0.130	1,200	**0.165**	1,400	**0.270**	1,800
0.125	1,300	**0.160**	1,500	**0.265**	2,000
0.120	1,500	**0.155**	1,600	**0.260**	2,100
0.115	1,700	**0.150**	1,900	**0.255**	2,300
0.110	2,000	**0.145**	2,200	**0.250**	2,700
0.105	2,500	**0.140**	2,800	**0.245**	4,600
0.100	5,000	**0.135**	4,600	**0.240**	4,800
0.095	5,300	**0.130**	4,900	**0.235**	5,000
0.090	5,700	**0.125**	5,200	**0.230**	5,200
0.085	6,100	**0.120**	5,500	**0.225**	5,300
0.080	6,500	**0.115**	5,700	**0.220**	5,400
		0.110	6,000	**0.215**	5,600
		0.105	6,500	**0.210**	5,700
				0.205	5,900
				0.200	6,100
				0.195	6,200
				0.190	6,500

EUG 6: Simple Cycle Combustion Turbines

Emission units AN-UNIT9, AN-UNIT10, and AN-UNIT11 (General Electric (GE) LM6000 Sprint™ combustion turbines) shall be subject to the following limitations:

	Each Turbine		Three Turbines Combined
Pollutant	**lb/hr**[a]	**ppmvd**[a,b]	**TPY**[c,g]
NO_X	42.0[e]	25[f]	161
CO	65.5[e]	63 (75-100% loads)[f]	248
VOC	2.3	--	9
SO_2	1.5	--	6
PM_{10}[d]	4.0	--	15.0
H_2SO_4	0.23	--	0.87

a) Excludes start-up and shut down
b) All concentrations are corrected to 15% O_2 per turbine
c) Twelve-month rolling total
d) PM_{10} limits are for filterable plus condensable PM_{10}
e) Three-hour rolling average
f) Annual rolling average
g) Inclusive of start-up and shut down emissions

A. Operation of EUs AN-UNIT9, AN-UNIT10, and AN-UNIT11 shall be limited to 2,500 hours each per rolling 12-month period.
B. EUs AN-UNIT9, AN-UNIT10, and AN-UNIT11 shall be limited to 250 start-up/shut down events per year per turbine.
C. Start-up periods per turbine shall not exceed a 2-hour period per occurrence, and shut down periods per turbine shall not exceed a 2-hour period per occurrence.
D. **Start-up** begins when fuel is supplied to the combustion turbine and ends when the combustion turbine reaches 25% load.
E. **Shut down** begins when the combustion turbine reaches 25% load and ends with the termination of fuel flow to the combustion turbine.
F. One **start-up/shut down event** is equivalent to one start-up (0 to 25 percent load) plus one shut down (25 to 0 percent load).
G. The following emission factors shall be used to calculate emissions for start-up and shut down events for Annual Emissions Inventory reporting purposes:

Pollutant	lb/Start-up per Turbine	lb/Shut Down per Turbine
NO_x	4.30	4.30
CO	3.70	3.70
SO_2	0.21	0.21
VOC	0.10	0.10
PM/PM_{10}	0.40	0.40
H_2SO_4 Mist	0.033	0.033

2. Compliance with the emission limitations specified in Specific Condition No. 1 shall be demonstrated based on performance testing, CEMs data, Part 75 monitoring procedures, or use of applicable emission factors referenced in the Permit Memorandum associated with this permit. [OAC 252:100-8-6(a)]

3. Emission units AN-UNIT9, AN-UNIT10, and AN-UNIT11 shall have a permanent (non-removable) identification plate attached that shows the make, model number, and serial number. [OAC 252:100-8-6]

4. Emissions from emission units AN-UNIT9, AN-UNIT10, and AN-UNIT11 shall be controlled by water injection, which shall be properly operated and maintained to satisfy BACT requirements (25ppm @ 15% O_2). [OAC 252:100-8-34]

5. Emission units AN-UNIT9, AN-UNIT10, and AN-UNIT11 shall only be fired with pipeline-quality natural gas. [OAC 252:100-31 & 8-34]

6. Emission units AN-UNIT9, AN-UNIT10, and AN-UNIT11 are subject to the federal New Source Performance Standards (NSPS) for Stationary Gas Turbines, 40 CFR 60, Subpart KKKK, and shall comply with all applicable requirements. [40 CFR Part 60, Subpart KKKK]

a) 60.4320: Standard for nitrogen oxides
b) 60.4330: Standard for sulfur dioxide
c) 60.4335 and 60.4365: Monitoring of operations
d) 60.4405 and 60.4415: Test methods and procedures

7. Performance testing shall be conducted on emission units AN-UNIT9, AN-UNIT10, and AN-UNIT11 within 180 days following commencement of operations of each new turbine. [OAC 252:100-43]

A. The following reference methods specified in 40 CFR 60 shall be used:

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 5: Determination of Particulate Matter from Stationary Sources
Method 7 or 7E: Determination of Nitrogen Oxide Emissions from Stationary Sources
Method 10: Determination of Carbon Monoxide Emissions from Stationary Sources
Method 18 or 25A: Determination of Volatile Organic Compounds Emissions from Stationary Sources
Method 201/201A: Determination of PM_{10} Emissions
Method 202: Determination of Condensable Particulate Emissions

B. Performance testing shall be conducted while the units are operating under representative conditions within 10% of maximum production rate.
C. A protocol describing the testing plan shall be submitted to the Air Quality Division at least 30 days prior to the testing.

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

8. When monitoring shows concentrations in excess of the ppm and lb/hr, or lb per start-up or shut down event limits of Specific Condition No. 1, the permittee shall comply with the provisions of OAC 252:100-9 for excess emissions. [OAC 252:100-9]

9. Monitoring shall be performed in compliance with the requirements of 40 CFR Part 75. [40 CFR Part 75]

10. The permittee shall maintain records as listed below. These records shall be maintained on-site for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-43]

A. Hours of operation of each turbine (monthly and 12-month rolling totals).
B. Sulfur content of natural gas (one of the methods from Specific Condition 6).
C. CEMS data required by the Acid Rain program.
D. Records required by NSPS Subpart KKKK.

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

A. 40 CFR Part 60, NSPS except for Subpart A and Subpart KKKK
B. 40 CFR Part 61, NESHAP
C. 40 CFR Part 63, NESHAP
D. 40 CFR Part 64, Compliance Assurance Monitoring
E. 40 CFR Part 68, Chemical Accident Prevention Provisions
F. OAC 252:100-19 (PM), all but Sections 1 and 4.

12. No later than 30 days after each anniversary date of the issuance of the original Title V operating permit for this facility (June 6, 2000), 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) & (D)]

13. No later than 180 days after operational start-up of the first turbine, the permittee shall submit to the Air Quality Division of the DEQ, with a copy to the US EPA, Region 6, an application to incorporate the turbines into the facility's Part 70 operating permit. [OAC 252:100-8-6]

14. EU AN-UNIT9, AN-UNIT10, and AN-UNIT11 are subject to the Acid Rain requirements of 40 CFR Parts 72, 73, and 75. The facility shall submit an application for an Acid Rain Permit at the same time that they submit the application for an operating permit for these units.

Western Farmers Electric Cooperative
Attn: Mr. Gerald Butcher
P.O. Box 429
Anadarko, OK 73005

SUBJECT: Construction Permit No. 2005-037-C (M-2) PSD
Install Three Combustion Turbines at Anadarko Power Plant
Location: Section 14, T7N, R10W, Caddo County, Oklahoma

Dear Mr. Butcher:
Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to standard and specific conditions, which 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.

Sincerely,

Donna Lautzenhiser, E.I.
New Source Permit Section
AIR QUALITY DIVISION

Enclosures

PART 70 PERMIT

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

Permit No. 2005-037-C (M-2) PSD

Western Farmers Electric Cooperative,

having complied with the requirements of the law, is hereby granted permission to construct three 50-MW simple-cycle combustion turbines at the Anadarko Power Plant located in the NW/4 portion of Section 14, T7N, R10W, Caddo County subject to standard conditions dated January 24, 2008, and specific conditions, both attached.

This permit shall expire 18 months from the date of issuance, except as Authorized under Section VIII of the Standard Conditions.

Division Director, Air Quality Division	**Date**

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(January 24, 2008)

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, 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 document 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." However, an exceedance report that must be submitted within ten days of the exceedance under Section II (Reporting Of Deviations From Permit Terms) or Section XIV (Emergencies) may be submitted without a certification, if an appropriate certification is provided within ten days thereafter, together with any corrected or supplemental information required concerning the exceedance.

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1) and OAC 252:100-9-3.1(c)]

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]

I. 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)]

J. 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]

K. 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).

L. 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, 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. 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)(A), (C)(v), 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; and a statement that the facility will continue to comply with all applicable requirements.

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

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:

(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).

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

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:

(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.

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

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:
   (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.

[OAC 252:100-25]

(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:

(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.

[40 CFR 82, Subpart A]

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:

(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.

[40 CFR 82, Subpart F]

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]