OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **January 15, 2013**

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

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

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

THROUGH: Peer Review

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

SUBJECT: Evaluation of Permit Application No. **2011-228-C (M-1)(PSD)**
Public Service Company of Oklahoma (PSO)
Southwestern Power Station
Addition of Low-NOx Burners and Overfire Air Systems
Washita, Caddo County
Sec. 10 – T7N – R11W
Directions: From Anadarko, 7 Miles West on SH-9, North 2 Miles, East 0.5 Mile, North 2 Miles
Latitude: 35.093^{o}N, Longitude -98.347^{o}

SECTION I. INTRODUCTION

Public Service Company of Oklahoma (PSO) has requested a PSD construction permit for modifications to their Southwestern Power Station, an electric generating station (SIC Code 4911). This permitting action will include a previous application to incorporate BART SIP requirements into the facility Title V operating permit. The facility is currently operating as authorized by Permit No. No. 2011-228-TVR, issued October 12, 2011.

As a result of the Regional Haze Rule and Best Available Retrofit Technology (BART) rules, PSO is installing Low-NOx burners and overfire air (OFA) systems on their Unit No. 3. Unit 3 is a 3,290 MMBTUH gas-fired boiler installed in 1967. In the OFA system, approximately 80% of the necessary combustion air is supplied to the burners directly, with the remaining 20% supplied just above the combustion zone. This reduces the amount of oxygen in the hottest part of the flame and reduces NOx. However, the changes to combustion result in increases in CO and VOC.

Since the project involves a physical change to an existing unit, the applicant has prepared a PSD analysis of Projected Actual Emissions (PAE) compared to Baseline Actual Emissions. Full PSD review is required for CO emissions.

In addition, this permit will submit to public review the results of the BART analysis prepared by AQD on January 19, 2010.

SECTION II. FACILITY DESCRIPTION

The existing facility produces power using four Babcock and Wilcox pressure-fired steam generators. The total combined steam output from the steam generators is sufficient to generate 500 MW-Gross. The steam is produced by these boilers to drive turbine-generators. Boilers are primarily run on natural gas with No. 2 fuel oil as an alternate fuel, along with small periodic quantities of "on-spec" used oil. Pipeline quality natural gas has been the primary fuel for the boilers since 1995. All four boilers are capable of operating on a continuous basis, but only the #3 boiler is actually operated continuously due to business demand. The other generators, #1N, #1S, and #2 are peaking units, which operate only when it is economically feasible, such as during peak demand. However, the estimated potential emissions listed in the emissions table are based on continuous operation of all four boilers. Also on site are one 2,847-hp diesel-fired emergency generator and seven storage tanks: two 2,100,000-gallon fuel oil tanks, one 84,000-gallon diesel fuel tank, one 16,800-gallon natural gas condensate tank, and three 3,000-gallon lube oil tanks.

PSO has constructed two natural gas-fired combustion turbine electric generating peaking units. The power block consists of two GE7EA simple cycle combustion turbine generators (CTGs). Each of the turbines has a peak heat input of approximately 1,078 MMBTUH and an average heat input of approximately 930 MMBTUH. The combustion turbines fire pipeline-quality natural gas only and are equipped with General Electric's 9/42 Dry low-NO_x (DLN) combustor technology. The new units have a combined nominal electrical generating capacity of 172 MW.

The permittee is authorized to evaporate non-hazardous boiler chemical cleaning waste (BCCW), and to combust on-spec used oil. The BCCW and on-spec used oil may be either generated on-site or from other PSO facilities. These operations may be conducted on an as-needed basis.

SECTION III. EQUIPMENT

Emission units (EUs) have been arranged into Emission Unit Groups (EUGs) in the following outline.

EUG 1 Steam Generators

EU ID#	Point ID#	EU Name, Model	MMBTUH	MW Gross	Serial No.	Const. Date
1N	1N	Babcock/Wilcox, S-1853	482**	42	17210	Jan. 1952*
1S	1S	Babcock/Wilcox, S-9747	482**	42	17209	Jan. 1952*
2	2	Babcock/Wilcox, S-9742	940**	84	17438	Feb. 1954*
3	3	Babcock/Wilcox, RB-426	3,290**	332	BW21718	May 1967*

*Date is actual start-up date, not construction start date due to the lack of records available.
**Actual full load used by system operations.

EUG 2 VOL Storage Tanks

EU ID#	Point ID#	Contents	Capacity		Construction Date
			Barrels	Gallons	
TANK1	T-1	Fuel Oil	50,000	2,100,000	1952
TANK2	T-2	Fuel Oil	50,000	2,100,000	1954
TANK3	T-3	Diesel Fuel	2,000	84,000	1954
TANK4	T-4	Condensate	400	16,800	1980*
TANK5	T-5	Lube Oil	71.5	3,000	1954
TANK6	T-6	Lube Oil	71.5	3,000	1966
TANK7	T-7	Lube Oil	71.5	3,000	1966
TANK8	T-8	Condensate	100	4,200	1997 **
TANK9	T-9	Condensate	2	84	2010

*This tank is owned and operated by the natural gas supplier, Enogex, Inc.
****** This tank is owned and operated by the natural gas supplier, Oklahoma Gas and Transmission.

EUG 3 Emergency Generator

EU ID#	Point ID#	EU Name/Model	hp	Serial No.	Mfg. Date*
EG1	EG1	**Caterpillar 3500**	2,847	4XF00410	1995

*This unit was moved to Southwestern Power Station in 2009.

EUG 4 Fugitive Emissions

Fugitive emissions from this facility are expected to be negligible.

EUG 5 New Combustion Turbines

EU ID#	Point ID#	EU Name, Model	MMBTUH	MW Gross	Serial No.	Installed Date
4	4	GE7EA Combustion Turbine	1,078	81	297223	2007
5	5	GE7EA Combustion Turbine	1,078	81	297224	2007

Both turbines were manufactured in 2002.

EUG 6: High Pressure Gas Yard Heater

EU ID#	Point ID#	Description	MMBTUH	Const. Date
6	6	Gas-fired heater	5.6	2009

SECTION IV: BART ANALYSIS

After considering: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollutant equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility (all five statutory factors) from each proposed control technology, the Division determined BART for the unit at the Southwestern Power Station.

New LNB with OFA is determined to be BART for NOx control for Unit 3 based, in part, on the following conclusions:

1. Installation of new LNB with OFA was cost effective, with a capital cost of $3,000,000 and an average cost effectiveness of $947 per ton of NOX removed over a twenty year operational life.

2. Combustion control using the LNB/OFA does not require non-air quality environmental mitigation for the use of chemical reagents (i.e., ammonia or urea) and there is minimal energy impact.

3. After careful consideration of the five statutory factors, especially the costs of compliance NOx control levels on 30-day rolling averages of 0.45 lb/MMBTU for Unit 3 are justified.

4. Annual actual NOx emission reductions from new LNB with OFA on Unit 3 are 450 tons.

LNB with OFA and SCR was not determined to be BART for NOx control for Unit 3 based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on each unit is significantly higher than the cost for LNB with OFA. Additional capital costs for SCR on Unit 3 are $65,968,400. Based on projected actual emissions, SCR could reduce overall NOx emissions from Southwestern Unit 3 by approximately 1,441 tpy (compared to combustion controls); however, the incremental cost associated with this reduction is approximately $10,281,677 per year, or $6,859/ton.

2. Additional non-air quality environmental mitigation is required for the use of chemical reagents.

3. Operation of LNB with OFA and SCR is parasitic and requires power from each unit.

4. SCR control may not be as effective on boilers that operate as peaking units, as NOx reduction in an SCR is a function of flue gas temperature.

The Division considers the installation and operation of the BART determined NOx controls, new LNB with OFA, to meet the statutory requirements of BART.

SECTION V. EMISSIONS

Air emissions and emissions changes from the facility have been calculated using the following methods and factors:

A. Emissions Changes

Except for CO, Baseline Actual Emissions were determined from previous years' inventories; for CO, BAE were determined from recent stack testing which showed CO emissions below detectable levels. As allowed by NSR Reform, different years were used for each pollutant. Greenhouse gas emissions are not expected to be affected by the project.

Table 1 Determination of Baseline Actual Emissions for Boiler 3

Pollutant	Inventory Years	Year 1 TPY	Year 2 TPY	BAE TPY
NOx	2007-2008	1973.37	2120.32	2046.85
CO	2008-2009	0	0	0
SO_2	2010-2011	2.55	2.45	2.50
PM_{10}	2008-2009	31.60	28.84	30.22
$PM_{2.5}$	2008-2009	31.60	28.84	30.22
VOC	2010-2011	2.54	2.74	2.64
GHG	2008-2009	495,902	452,868	474,385

Post-project emissions were determined using the following emissions factors and a projected maximum heat input of 8,111,461 MMBTU per year, a usage determined from "ProMod" software. (It should be noted that demand growth, which could be excluded for PAE purposes, have been included in the projected utilization.) The facility has relinquished authority to burn oil fuel in Unit No. 3. PAE were based on natural gas fuel as follows:

Table 2 Post-Project Emissions Factors for Boiler 3

Pollutant	Emission Factor, lb/MMBTU	Factor Reference
NOx	0.450	Vendor guarantee
CO	0.15	Vendor guarantee of 100 ppm @ 3% O_2
SO_2	0.0006	AP-42 (7/98) Section 1.4, adjusted to 1,040 BTU/SCF
PM_{10}	0.0075	AP-42 (7/98) Section 1.4, adjusted to 1,040 BTU/SCF
$PM_{2.5}$	0.0075	AP-42 (7/98) Section 1.4, adjusted to 1,040 BTU/SCF
VOC	0.0054	AP-42 (7/98) Section 1.4, adjusted to 1,040 BTU/SCF
GHG	116.7	40 CFR Part 98

Table 3 Net Emissions Changes for Boiler 3 (8,111,461 MMBTU/yr)

Pollutant	Emission Factor, lb/MMBTU	Projected Actual Emissions TPY	Baseline Actual Emissions TPY	Net Changes TPY	PSD Level of Significance TPY
NOx	0.450	1825.08	2046.85	-221.77	40
CO	0.15	608.36	0	608.36	100
SO_2	0.0006	2.43	2.50	-0.07	40
PM_{10}	0.0075	30.42	30.22	0.20	15
$PM_{2.5}$	0.0075	30.42	30.22	0.20	10
VOC	0.0054	21.90	2.64	19.26	40
GHG	116.7	474,385	474,385	0	75,000

Only CO net emissions changes are above PSD levels of significance.

B. Criteria Pollutants

The estimated potential criteria pollutants emissions from boilers and heater are based on the emission factors in AP-42 (7/98), Tables 1.4-1 and 1.4-2, Section 1.4, "Natural Gas Combustion" when gas is burned. The emission factors from AP-42 (9/98), Tables 1.3-1, 1.3-2, and 1.3-3, Section 1.3, "Fuel Oil Combustion" are used when the No. 2 fuel oil (average heating value of 140 MBTU/gal and 0.7 wt % sulfur) is burned.

Table 4 Emission Factors for Boilers (lb/MMBTU)

Fuel	NOx	CO	SO_2	VOC	PM
Natural Gas	1.126 hourly 0.2800 annual	0.0840	0.0006	0.0055	0.0076
No. 2 Fuel Oil	0.1714	0.0357	0.7100	0.0054	0.0143

NOTE: stack testing showed CO emissions from Unit 3 to be non-detectable, so this factor cannot be used for netting purposes.

The criteria pollutants emissions from the emergency generator are based on the emission factors in AP-42 (10/96), Tables 3.4-2 and 3.4-5, Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines."

Table 5 Emission Factors for Emergency Generator (lb/MMBTU)

Fuel	NOx	CO	SO_2	VOC	PM
No. 2 Fuel Oil	3.100	0.081	0.707	0.100	0.0573

The estimated potential emissions for the facility are based on the 8,760 hours/year continuous operation for the boilers, and 500 hours/year for the emergency generator. The selection of 500 hours/year is based on the EPA memo (September 6, 1995), entitled "Calculating Potential to Emit for Emergency Generators" which states that 500 hours is an appropriate default for estimating emissions from these sources.

Table 6 Emissions from Emergency Generator

EU	NOx		CO		SO_2		VOC		PM	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Replacement Unit EG1	22.42	5.60	0.59	0.15	5.11	1.28	0.73	0.18	0.41	0.11

Table 7 presents the facility-wide estimated potential emissions from natural gas combustion and Table 8 presents the facility-wide estimated potential emissions from No. 2 fuel oil combustion.

Table 7 Facility-Wide Existing Potential Emissions from Natural Gas Combustion

EU	NOx		CO		SO_2		VOC		PM	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Unit 1N	134.96	591.12	40.49	177.34	0.29	1.27	2.65	11.61	3.66	16.04
Unit 1S	134.96	591.12	40.49	177.34	0.29	1.27	2.65	11.61	3.66	16.04
Unit 2	263.20	1152.82	78.96	345.84	0.56	2.47	5.17	22.64	7.14	31.29
Unit 3	3704.54	4034.86	276.36	1210.46	1.97	8.65	18.10	79.26	25.00	109.52
Unit EG1	22.42	5.60	0.56	0.14	4.85	1.21	0.69	0.17	0.39	0.10
TOTALS	**4260.08**	**6375.52**	**436.85**	**1911.12**	**7.97**	**14.86**	**29.25**	**125.29**	**39.87**	**173.00**

Table 8 Facility-Wide Existing Potential Emissions from No. 2 Fuel Oil Combustion

EU	NOx		CO		SO_2		VOC		PM	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Unit 1N	82.61	361.85	17.21	75.37	378.37	1657.26	2.60	11.40	6.89	30.19
Unit 1S	82.61	361.85	17.21	75.37	378.37	1657.26	2.60	11.40	6.89	30.19
Unit 2	161.12	705.69	33.56	146.98	737.90	3232.00	5.08	22.23	13.44	58.88
Unit EG1	22.42	5.60	0.56	0.14	4.85	1.21	0.69	0.17	0.39	0.10
TOTALS	**348.76**	**1434.99**	**68.54**	**297.86**	**1499.49**	**6547.73**	**10.97**	**45.20**	**27.61**	**119.36**

Criteria pollutant emissions from the combustion turbines are estimated based on GE vendor-supplied emissions data and BACT limits for NOx, CO and PM_{10}. Estimated emissions summarized in the table below are based upon this peaking operation profile at a nominal 2,000 hours per year per unit.

In order to allow for flexibility in operations, the permit limits the annual fuel usage in the two combustion turbines combined to 4,228 MMscf/yr rather than set fuel usage or hours of operation limits on each turbine individually. This allows PSO to operate each combustion turbine based on demand for power since one unit or several units may not operate at full capacity. In addition, this allows PSO to operate one combustion turbine at the facility if the other turbine is unavailable due to malfunction or maintenance issues.

Table 9 Emission Factors for Turbines

Pollutant	Units	Emission Factor
NO_X	ppmvd @ 15% O_2	9
CO	ppmvd @ 15% O_2	25
VOC	ppmvd @ 15% O_2	1.4
PM_{10}	lb/hr	10
SO_2	lb/MMBTU	0.012
H_2SO_4	% of SO_2	10%

Table 10 Potential Emissions from Combustion Turbines

EU	NOx		CO		SO_2		VOC		PM	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Unit 4	35.00	42.29	59.00	71.30	15.00	0.75	2.00	2.00	10.00	10.00
Unit 5	35.00	42.29	59.00	71.30	15.00	0.75	2.00	2.00	10.00	10.00
TOTALS	**70.00**	**84.59**	**118.00**	**142.59**	**30.00**	**1.51**	**4.00**	**4.00**	**20.00**	**20.00**

The applicant expects a large amount of additional emissions resulting from start-ups and shutdowns. Due to their operation as peaking units, these turbines can be expected to experience a regular cycle of startup and shutdown events during which NO_x and CO emission rates are higher than at normal baseload levels. These elevated levels of emissions are accounted for in the pollutant estimates described below. Weekly emission calculations are based on an average of one cold start day per week and three warm start days per week.

PSO requested an emissions limit for both turbines combined as opposed to individual emissions limits. By incorporating elevated emission rates during startup and shutdown, higher than during normal operations, the emissions listed above represent the most conservative estimate for the annual emission totals.

Table 11 Estimated Daily Peaking Operation

Cold Start Day	Hours of Operation	NO_x[1]		CO[2]	
		lb/hr	lb/event	lb/hr	lb/event
Normal Operation	9.82	35.00	343.70	59.00	579.38
Cold Start	2	186.06	372.12	313.64	627.28
Shutdown	1	20.29	20.29	34.20	34.20
Downtime	11.18	-	-	-	-
Total (per day)	**24**	**-**	**736.11**	**-**	**1,240.86**

Warm Start Day	Hours of Operation	NO_x[1]		CO[2]	
		lb/hr	lb/event	lb/hr	lb/event
Normal Operation	9.82	35.00	343.70	59.00	579.38
Warm Start	2	56.81	113.62	95.77	191.54
Shutdown	1	20.29	20.29	34.20	34.20
Downtime	11.18	-	-	-	-
Total (per day)	**24**	**-**	**477.61**	**-**	**805.12**

1) Normal operation NOx emission factor based on 9 ppm. Emissions during startup/shutdown based upon CEMS data from operation of a similar-sized GE turbine.
2) Normal operation CO emission factor based on 25 ppm. Emissions during startup/shutdown based upon CEMS data from operation of a similar-sized GE turbine.

Table 12 Estimated Weekly Peaking Emissions

Cold Start	Hours/ Day	Days/ Week	Hours/ Week	NO_x			CO		
				lb/hr	lbs/ week	tons/ week	lb/hr	lbs/ week	tons/ week
Normal Operation	9.82	1	9.82	35.00	343.70	0.17	59.00	579.38	0.29
Cold Start	2	1	2	186.06	372.12	0.19	313.64	627.28	0.31
Shutdown	1	1	1	20.29	20.29	0.01	34.20	34.20	0.02
Downtime	11.18	1	11.18	-	-	-	-	-	-
Subtotal	24			-		0.37	-		0.62
Warm Start				**lb/hr**	**lbs/ week**	**tons/ week**	**lb/hr**	**lbs/ week**	**tons/ week**
Normal Operation	9.82	3	29.46	35.00	1031.1	0.52	59.00	1738.14	0.87
Warm Start	2	3	6	56.81	340.86	0.17	95.77	574.62	0.29
Shutdown	1	3	3	20.29	60.87	0.03	34.20	102.6	0.05
Downtime	11.18	3	33.54	-	-	-	-	-	-
Subtotal	24			-	-	0.72	-	-	1.21
Total				**-**	**-**	**1.08**	**-**	**-**	**1.83**

Table 13 Estimated Annual Peaking Emissions

	Hours/ Week	Weeks/ Year	Hours/ Year	NO_x		CO	
				lb/hr	TPY	lb/hr	TPY
Normal Operation	39.28	39	1,532	35.00	26.81	59.00	45.19
Cold Start	2	39	78	186.06	7.26	313.64	12.23
Warm Start	6	39	234	56.81	6.65	95.77	11.20
Shutdown	4	39	156	20.29	1.58	34.20	2.67
Downtime	44.72	39	-	-	-	-	-
Total			**2,000**		**42.29**		**71.30**

C. Hazardous Air Pollutants (HAPs)

HAP emissions from the turbines are based on AP-42, Section 3.1 (4/2000). HAP emissions from the existing boilers are based on AP-42, Section 1.4 (9/98) for gas fuel. HAP emissions from the emergency generator are based on AP-42, Section 3.4 (10/96) but are considered negligible compared to the larger units.

Table 14 Existing Facility HAPs When Burning Gas Fuel

Unit Capacity MMBTUH	Fuel Heating Value BTU/SCF	Fuel Usage MMSCFH	Fuel Usage MMSCFY	HAP	Emission Factor lb/MMSCF	Emissions	
						lb/hr	TPY
5,194	1,020	5.09	44,607	7,12-Dimethylbenz(a) anthracene	0.000016	0.001	0.000
				Anthracene	0.0000024	0.001	0.001
				Benz-a-anthracene	0.0000018	0.001	0.001
				Benzene	0.0021	0.011	0.047
				Dibenzo(a,h)anthracene	0.0000012	0.001	0.001
				Dichlorobenzene	0.0012	0.006	0.027
				Formaldehyde	0.075	0.382	1.673
				Hexane	1.8	9.166	40.147
				Naphthalene	0.00061	0.003	0.014
				Phenanthrene	0.000017	0.001	0.001
				Toluene	0.0034	0.017	0.076
				Arsenic	0.0002	0.001	0.004
				Beryllium	0.000012	0.001	0.001
				Cadmium	0.0011	0.006	0.025
				Chromium	0.0014	0.007	0.031
				Cobalt	0.000084	0.001	0.002
				Manganese	0.00038	0.002	0.008
				Mercury	0.00026	0.001	0.006
				Nickel	0.0021	0.011	0.047
				Selenium	0.000024	0.001	0.001
				Vanadium	0.0023	0.012	0.051

Hexane emissions are above major source thresholds.

Table 14 New Turbines HAPs When Burning Gas Fuel

Unit Capacity MMBTUH	Fuel Heating Value BTU/SCF	Fuel Usage MMSCFH per Turbine	Total Annual Fuel Usage MMSCFY	HAP	Emission Factor lb/MMBTU	Combined Emissions	
						lb/hr	TPY
1,078	1,020	2,114	4,228	1,3-Butadiene	0.00000043	0.001	0.001
				Acetaldehyde	0.000040	0.085	0.085
				Acrolein	0.0000064	0.014	0.014
				Benzene	0.000012	0.025	0.025
				Ethylbenzene	0.000032	0.068	0.068
				Formaldehyde	0.00071	1.501	1.501
				Naphthalene	0.0000013	0.003	0.003
				PAH	0.0000022	0.005	0.005
				Propylene oxide	0.000029	0.061	0.061
				Toluene	0.00013	0.275	0.275
				Xylene	0.000064	0.135	0.135

Table 15 Existing Facility HAPs When Burning Liquid Fuel

Total Capacity MMBTUH	Fuel Heating Value BTU/Gal	Fuel Usage Mgal/hr	Fuel Usage Mgal/yr	HAP	Emission Factor lb/Mgal	Emissions	
						lb/hr	TPY
1,904	140,000	13.6	119,136	Anthracene	1.22E-06	0.001	0.001
				Benz-a-anthracene	4.01E-06	0.001	0.001
				Benzene	0.000214	0.003	0.013
				Dibenzo(a,h)anthracene	1.67E-06	0.001	0.001
				Ethyl benzene	0.0000636	0.001	0.040
				Formaldehyde	0.033	0.449	1.966
				Naphthalene	0.00113	0.015	0.067
				PCDD	3E-09	0.001	0.001
				Phenanthrene	0.0000105	0.001	0.001
				Toluene	0.0062	0.084	0.369
				Antimony	0.00525	0.071	0.313
				Arsenic	0.00132	0.018	0.078
				Beryllium	0.0000278	0.001	0.001
				Cadmium	0.000398	0.005	0.024
				Chromium	0.000845	0.011	0.050
				Cobalt	0.00602	0.082	0.356
				HCl	0.347	4.719	20.670
				HF	0.0373	0.507	2.222
				Lead	0.00151	0.020	0.090
				Manganese	0.003	0.047	0.179
				Mercury	0.000113	0.001	0.07
				Nickel	0.0845	1.149	5.033
				Selenium	0.000683	0.009	0.041
				Vanadium	0.0318	0.433	1.894

D. Greenhouse Gas Emissions

Total potential greenhouse gas emissions have been stated at 3,768,439 TPY CO_2e using the methods of 40 CFR Part 98 and total potential fuel usage of 7,356 MMBTUH.

SECTION VI. PSD REVIEW

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

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

The project is driven by NOx reductions needed to achieve BART compliance. There is an inverse relationship between NOx and CO emissions, i.e., procedures which reduce NOx result in increased CO emissions, and vice versa.

A. BACT

A BACT analysis is required for each new or physically modified emissions unit for each pollutant which exceeds an applicable PSD Significant Emission Rate (SER). The pollutant subject to review under the PSD regulations is carbon monoxide (CO). The BACT review follows the “top-down” approach recommended by the EPA.

BACT must be at least as stringent as any NSPS applicable to the emissions source. After determining whether any NSPS is applicable, the first step in this approach is to determine for the emission unit in question the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically infeasible for the unit in question, the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical or environmental concerns. The remaining technologies are evaluated on the basis of operational and economic effectiveness. 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.

Presented below are the five basic steps of a top-down BACT review procedure as identified by the U.S. EPA in the March 15, 1990, Draft BACT Guidelines:

Step 1. Identification of all control technologies
Step 2. Determination of technical feasibility of control options
Step 3. Ranking of remaining control technologies by control effectiveness
Step 4. Evaluation of most effective controls and document results
Step 5. Selection of BACT

Control technologies and related emissions data were identified through a review of 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.

Step 1: Identify All Control Technologies

CO Control Technologies

Carbon monoxide is formed as a result of incomplete combustion of fuel. 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. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors however tend to result in high NO_X emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve lowest NO_X emissions rate possible while also optimizing CO emission rates.

A review of EPA's RACT/BACT/LAER Clearinghouse indicated that CO emission control methods include exhaust gas cleanup methods such as thermal or catalytic oxidation, and front-end methods such as combustion control wherein CO formation is suppressed within the combustors.

Good Combustion Practices

According to the EPA's RBLC database, the only recent BACT determination for CO was use of good combustion practices. Efficient burners can minimize the formation of CO by providing excess oxygen, mixing the fuel thoroughly with air and by employing general good combustion practices. The CO emission limit set for installations with good combustion practices BACT were 0.15 lb/MMBTU.

Catalytic Oxidation

Another CO control technology for natural gas fired boilers is an oxidation catalyst system. Just like with SCR catalyst technology for NO_X control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to proceed. Rather, the oxidation catalyst utilizes the excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. The oxidation is carried out by the following overall reaction:

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2$$

This reaction is promoted by several noble metal-enriched catalysts at high temperatures. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}. Under ideal operating conditions, this technology can achieve an 80% reduction in CO emissions.

As with SCR, CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700°F to 1,100°F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1,200°F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the boiler exhaust lateral distribution. It is important that the gas flow is evenly distributed across the catalyst and that proper operating temperature at base load design conditions is maintained.

Catalyst systems are subject to loss of activity over time. Catalyst fouling occurs slowly under normal operating conditions and may be accelerated by even moderate sulfur concentrations in the exhaust gas. The catalyst can be chemically washed to restore its effectiveness, but eventually, irreversible degradation occurs. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5 to 7 year predicted life. Periodic testing of catalyst material is necessary to predict actual catalyst life for a given installation. The following economic analysis assumes that catalyst will be replaced every 3 years per vendor guarantee. This system also would be expected to control a small percent (5-40%) of hydrocarbon (VOC) emissions.

A CO catalyst also will oxidize other species within the boiler exhaust. For example, sulfur in natural gas (fuel sulfur and mercaptans added as an odorant) is oxidized to gaseous SO_2 within the combustor, but is further oxidized to SO_3 across a catalyst (30% conversion is assumed). SO_3 will then be emitted and/or combined to form H_2SO_4 (sulfuric acid mist) from the exhaust stack. These sulfates condense in the gas stream or within the atmosphere as additional PM_{10} (and $PM_{2.5}$). Thus, an oxidation catalyst would reduce emissions of CO and to some extent VOC, but would increase emissions of PM_{10} and $PM_{2.5}$. Also, the increased backpressure of the catalyst bed would require additional fuel firing to produce the same amount of electricity output, resulting in associated emission increases in other criteria pollutants.

According to the EPA's RBLC database, no application of thermal oxidation (e.g., a regenerative thermal oxidizer) is being used to control CO from a gas-fired boiler.

Step 2 – Determination of Technical Feasibility of Identified Control Options

The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those which are clearly technically infeasible are identified and not considered further.

Thermal oxidation is eliminated at this point as not being a demonstrated control technology.

Step 3 – Ranking of control technologies by control effectiveness

All identified controlled technologies and their control efficiencies are presented below. The technologies are ranked in order of decreasing effectiveness and the technologies determined as non-feasible are indicated as such.

Ranked Controlled Technologies by Control Efficiency

Pollutant	Control Technology	Control Efficiency (%)	Technical Feasibility
CO	Thermal Oxidation	80-90%	Not demonstrated
	Oxidation Catalyst	60 – 80	Feasible
	Good combustion practices	Base Case	Feasible

Step 4 – Evaluation of the most effective controls

There is no “Bright Line” cost effectiveness threshold for CO; rather, the cost presented for a specific project for control of CO are compared with the cost per ton that have been required of other sources in the same geographical area. For example, a project located in a rural attainment area where dispersion modeling shows less than significant air quality impacts would have a different cost criteria than a project located in or near an urban CO non-attainment area where there is a legitimate need to minimize emissions of CO. It should also be noted that cost effectiveness is a pollutant specific standard. For instance, the cost effectiveness of controlling the more pervasive pollutant NO_X (an acid rain pollutant, a precursor to the formation of regional haze, and a precursor to the formation of ozone) is aptly higher than for the more benign stack level emissions of CO. Areas of CO non-attainment are primarily urban and exceedances of the CO NAAQS are dominated by ground level releases due to automobiles. CO emitted from a power plant stack is quickly dispersed (as shown in the modeling analysis) and is an unstable molecule that naturally is converted to CO_2 in the atmosphere.

The use of an oxidation catalyst to control emissions of CO would result in collateral increases in PM_{10}(and $PM_{2.5}$ emissions. Further, the catalyst bed would create an increased backpressure which would require additional fuel firing to produce the same amount of electricity output, resulting in associated emission increases in other criteria pollutants. In addition, the cost effectiveness of a catalyst system to control emissions of CO is estimated at $9,600 per ton of removed CO, which is not economically feasible. Capital and annual costs associated with installation of an oxidation catalyst system were calculated using vendor quotes.

The fact that the use of oxidation catalyst for CO reduction would be associated with increase in other emissions, the very high cost per ton of this technology, as well as the regional air quality conditions, leads to the determination that combustion controls represent BACT for large gas-fired turbines. In addition, the resulting CO emissions do not exceed the Modeling Significance Levels (MSLs). There are no expected adverse economic, environmental or energy impacts associated with the use of the proposed control alternative. The proposed CO BACT limit is 0.15 lb/MMBTU.

Step 5 – Selection of BACT

Summary of Selected BACT for Boilers

Pollutant	Control Technology	Proposed Permit Limit
CO	Good combustion practices	0.15 lb/MMBTU

As previously mentioned, there is a single gas-fired boiler on the RBLC which is being retrofitted.

CO Requirement	Averaging Period	Facility/Unit Name	State	Date
0.15 lb/MMBTU	Annual	Cleco Rodemachere Power Station Unit 2	LA	2008

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

Model Selection and Description

Consistent with the available modeling applications provided for by Appendix W to Part 51 Guideline on Air Quality Models, the AERMOD PRIME (Version 12060) air dispersion model is used to predict maximum ground-level concentrations associated with the proposed project's emissions. AERMOD is a refined, multi-source Gaussian plume model. The modeling analysis was performed using regulatory default options including stack-tip downwash and missing data processing.

Source Input Parameters

The stack height for Unit 3 is 140 ft, and diameter is 14 feet, with a velocity of 53 ft/sec and temperature of 275^{o}F. The modeled CO emission rate is conservatively based on a 0.15 lb/MMBTU emission rate and the unit's heat input of 3,290 MMBTU/hr.

Good Engineering Practice and Building Downwash Evaluation

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

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

or by a height demonstrated by a fluid model or a field study that ensures that emissions from a stack do not result in excessive concentrations of any pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features.

The model utilizes the EPA Building Profile Input Parameters program. BPIP determines the effect of building downwash on each plume in calculation of maximum impacts.

Meteorology and Surface Characteristics

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

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

Terrain Considerations

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

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

Urban/Rural Classification

Section 8.2.3 of the GAQM provides the basis for determining the urban/rural status of a source. For most applications, the land use procedure described in Section 8.2.3(c) is sufficient for determining the urban/rural status. However, there may be sources located within an urban area, but located close enough to a body of water to result in a predominantly rural classification. In those cases, the population density procedure may be more appropriate. Because the PSO facility is not located within an urban area near a body of water, only the following land use procedure is used to assess the urban/rural status of the source.

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

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

Discrete and Flagpole Receptors

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

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

1. A Fence Line Grid containing receptors spaced at 40 meter intervals along the facility fence line.
2. A Fine Grid containing receptors spaced at 100 meter intervals extending approximately 1.0 km from the fence line, exclusive of the Fence Line Grid.
3. A 250-meter grid containing receptors spaced at 250 meter intervals extending approximately 2.5 km beyond the Fine Grid.
4. A 500-meter grid containing receptors spaced at 500 meter intervals extending approximately 5.0 km beyond the 250-meter grid.
5. A 750-meter grid containing receptors spaced at 750 meter intervals extending approximately 7.5 km beyond the 500-meter grid.
6. A 1,000-meter grid containing receptors spaced at 1,000 meter intervals extending approximately 50.0 km beyond the 750-meter grid.

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

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

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

Pollutant	Averaging Period	SIL $\mu g/m^3$	Max Impact $\mu g/m^3$	Full Impact Analysis Required?
CO	1-hr	2,000	1,188	No
	8-hr	575	565	No

C. Evaluation of PSD increment consumption

Because the project impact is less than the SIL, increment consideration is not necessary. In any event, there is no increment for CO.

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

Since added impacts are below PSD ambient levels of significance, a full analysis of compliance with NAAQS is not required for this project.

E. Ambient air monitoring

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

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

The facility has provided a brief review of these topics.

Commercial, Residential, and Industrial Growth Analysis

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

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

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

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

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

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

Visibility Impairment Analysis

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

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

Furthermore, a review of the Class I areas around the Southwest Power Station does not show any sensitive areas within 40 km. The nearest ODEQ listed sensitive area is the Wichita Mountains Wildlife Refuge, which is approximately 50 km from the station.

Vegetation Analysis

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

Unlike fauna, CO does not poison vegetation since it is rapidly oxidized to form carbon dioxide which is used for photosynthesis. However, extremely high concentrations can reduce the photosynthetic rate. According to the USEPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals*, hereafter referred to as USEPA Screening Document, for the most sensitive vegetation, a CO concentration of 1,800,000 $\mu g/m^3$ (1-week averaging period) could potentially reduce the photosynthetic rate. The maximum model-predicted 1-hour CO impact of 3,059 $\mu g/m^3$ produced by the facility is significantly lower than this screening level. Consequently, no adverse impacts to vegetation at or near the proposed project are expected from CO emissions.

Soils Analysis

As noted earlier, the maximum model-predicted ambient concentration of CO resulting from the facility is 3,059 $\mu g/m^3$, which is significantly less than the applicable ambient air quality standards and the NSR/PSD significant impact levels. Because the predicted CO air quality impacts resulting from the project are not significant, and are in fact orders of magnitude less than the applicable air quality standards designed to protect public health, it is reasonable to conclude that the proposed emissions of CO will not affect soils.

G. Evaluation of Class I Area Impact

Federally designated Class I areas are afforded special protection in the air permitting process. Generally, Class I area analyses are conducted only for projects located within 100 km of a Class I area. The Southwest Power Station is approximately 50 km from the closest Class I area, the Wichita Mountains Wildlife Refuge. Other Class I areas are more than 300 km distant. As the proposed project results in a substantial decrease in NO_X emissions and no increase in any other visibility impairing pollutants (i.e., SO_2, PM_{10}, and H_2SO_4), a Class I area analysis is not required for this project.

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

SECTION VII. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application are duplicated below. Records are available to confirm the insignificance of the activities. Appropriate recordkeeping of activities indicated below with "*" is specified in the Specific Conditions.

1. * Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or distillate fuel oil which are used exclusively for emergency power generation not to exceed 500 hours/year. The backup diesel generator is used for emergency power generation and is not expected to operate more than 500 hours/year. That generator will remain an "insignificant activity" until new standards under 40 CFR Part 63, Subpart ZZZZ, become applicable.

2. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTU/hr heat input (commercial natural gas). None identified but may be used in the future.

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

4. * Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature.

5. * Bulk gasoline or other fuel distribution with a daily average throughput less than 2,175 gallons per day, including dispensing, averaged over a 30-day period.

6. Gasoline and aircraft fuel handling activities, equipment, and storage tanks except those subject to New Source Performance Standards and standards in OAC 252:100-37-15, 252:100-39-30, 252:100-39-41, and 252:100-39-48.

7. * Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. None identified but may be used in the future.

8. Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in OAC 252:100-8-3(e)(1).

9. Cold degreasing operations utilizing solvents that are denser than air.

10. * Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes.

11. Torch cutting and welding of under 200,000 tons of steel fabricated per year.

12. Emissions from landfills and landfarms unless otherwise regulated by an applicable state or federal regulation.

13. Surface coating operations which do not exceed a combined total of more than 60 gallons per month of coatings, thinners, and clean-up solvents at any one emission unit.

14. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas.

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

16. * Activities that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant. The 5.6 MMBTUH heater is in this category.

SECTION VIII. OKLAHOMA AIR POLLUTION CONTROL RULES

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

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

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
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 Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. This facility has submitted the required emission inventories and has paid the applicable or fees.

OAC 252:100-8 (Major Source/Part 70 Permits) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (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 HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule

Emissions limitations have been established for each emission unit based on information from the current and previous permit application.

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

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

OAC 252:100-19 (Particulate Matter) [Applicable]
Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Appendix C specifies a PM emission limitation of 0.60 lbs/MMBTU for all equipment at this facility with a heat input rating of 10 Million BTU per hour (MMBTUH) or less. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Thus, the following equipment is subject to the requirements of this subchapter. Emission factors shown in Section III (Emissions) above indicate that all units are in compliance.

Equipment	Maximum Design Heat Input, (MMBTUH)	Appendix C Emission Limit, (lbs/MMBTU)	Potential Emission Rate, (lbs/MMBTU)
1N	482	0.24	0.0076
1S	482	0.24	0.0076
2	940	0.20	0.0076
3	3,290	0.15	0.0076
Unit 4	1,078	0.18	0.0093
Unit 5	1,078	0.18	0.0093

This subchapter also limits emissions of PM from industrial processes. Per AP-42 factors, there are no significant PM emissions from any other industrial activities at this facility.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. All of the emission units are subject to this subchapter. The turbines will assure compliance with this rule by ensuring "complete combustion" and utilizing pipeline-quality natural gas as the primary fuel.

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 originated 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 to interfere with the maintenance of air quality standards. No activities are expected that would produce fugitive dust beyond the facility property line.

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 turbines to be fired with pipeline-grade natural gas with SO_2 emissions limits equivalent to 0.012 lb/MMBTU. The "grandfathered" units pre-date these requirements.
Part 5 also requires an opacity monitor and sulfur dioxide monitor for equipment rated above 250 MMBTU. Equipment burning gaseous fuel is exempt from the opacity monitor requirement, and equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitoring requirement, so the turbines do not require such monitoring.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits emissions of NO_X from new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to a three-hour average of 0.2 lb/MMBTU. Listed below is the 3-hr average emission limit (lb/hr) of NO_X for each combustion turbine and the equivalent emission rates (lb/MMBTU) based on the maximum heat input, which are below the standard of 0.2 lb/MMBTU. The boilers pre-dated this rule and the Backup Diesel Generator is below 50 MMBTUH heat input and are, therefore, not subject to this rule.

Units	MMBTUH	lb/hr	lb/MMBTU
Turbines	1,078	35.00	0.047

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

OAC 252:100-37 (Volatile Organic Compounds) [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 at maximum storage temperature to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The fuel oil tank (T-1) and diesel fuel tank (T-2) are exempt based on vapor pressures below the 1.5 psia level.
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. No coating operation is located at this facility.
Part 7 requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. The equipment at this location is subject to this requirement.
Part 7 requires all effluent water separator openings which receive water containing more than 200 gallons per day of any VOC, to be sealed or the separator to be equipped with an external floating roof or a fixed roof with an internal floating roof or a vapor recovery system. No effluent water separators are located at this facility.

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

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

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

OAC 252:100-11	Alternative 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 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Municipal Solid Waste Landfills	not in source category

SECTION IX. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
The facility is a listed source as a fossil fuel-fired electric plant of more than 250 MMBTU heat input with emissions greater than 100 TPY. PSD review has been completed in Section VI.

NSPS, 40 CFR Part 60 [Subparts A and GG are Applicable]
Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected facilities. Within 30 days after starting construction 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 will 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 Da, Electric Utility Steam Generating Units. This subpart affects electric steam generating units with a design capacity greater than 250 MMBTUH, and combined cycle gas turbines that are capable of combusting more than 250 MMBTUH level in the heat recovery steam generator, that were constructed after September 18, 1978; and combined cycle gas turbines capable of combusting more than 250 MMBTUH heat input of fossil fuel (either alone or in combination with any other fuel), designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis that were constructed after February 28, 2005. Subpart Da affects emissions of NOx, SO_2, and PM. Since none of these pollutants are being increased, the facility is not being "modified" as defined by NSPS.
Subpart GG, Stationary Gas Turbines. This subpart affects combustion turbines which commenced construction, reconstruction, or modification after October 3, 1977, and which have a heat input rating of 10 MMBTUH or more. Each of the turbines has a rated heat input of greater than 10 MMBTUH and is subject to this subpart.

EPA guideline document EMTIC, GD-009 advises to use zero for the value of F with gas turbines. So, the lowest NO_X limit is 0.0075% or 75 ppmdv when Y = 14.4. The NO_X emission limitation for each turbine is 9 ppmdv at 15% O_2 and is therefore more stringent than the Subpart GG standards. Performance testing by Reference Method 20 is required. Monitoring fuel for nitrogen content is not required if the owner or operator does not claim an allowance for fuel bound nitrogen per 60.334(h)(2).

Sulfur dioxide standards specify that no fuel shall be used which exceeds 0.8% by weight sulfur or the exhaust gases shall not contain SO_2 in excess of 150 ppm. The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted if the gaseous fuel is demonstrated to meet the definition of "natural gas" using either the gas quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or using representative fuel sampling data. The maximum total sulfur content of "natural gas" is 20 grains/100 SCF (680 ppmw or 338 ppmv) or less.

Subpart KKKK affects stationary gas turbines that commenced construction, modification, or reconstruction after February 18, 2005. Although these turbines have been relocated to the Southwestern facility, they were originally manufactured pre-2003. As a result, Subpart KKKK does not apply.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: asbestos, benzene, beryllium, coke oven emissions, radionuclides, or vinyl chloride except for trace amounts of arsenic, benzene, beryllium, and mercury. Subpart J, Equipment Leaks of Benzene, concerns only process streams that contain more than 10% benzene by weight. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.

NESHAP, 40 CFR Part 63 [Not Applicable]

Subpart YYYY, Stationary Combustion Turbines. This subpart was promulgated on March 5, 2004 and affects stationary combustion turbines that are located at major source of HAP. The turbines were both built in 2002, therefore, are "existing" gas-fueled turbines. There are no standards in Subpart YYYY for existing units.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart previously affected only RICE with a site-rating greater than 500 brake horsepower that are located at a major source of HAP emissions. On January 18, 2008, the EPA published a final rule that promulgates standards for new and reconstructed engines (after June 12, 2006) with a site rating less than or equal to 500 HP located at major sources, and for new and reconstructed engines (after June 12, 2006) located at area sources. Owners and operators of new or reconstructed engines at area sources and of new or reconstructed engines with a site rating equal to or less than 500 HP located at a major source (except new or reconstructed 4-stroke lean-burn engines with a site rating greater than or equal to 250 HP and less than or equal to 500 HP located at a major source) must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines). The emergency engine at this facility pre-dates the new standards.

On March 3, 2010, EPA finalized additional requirements for stationary CI RICE. As an emergency CI engine larger than 500-hp located at a major source of HAP, the engine here is subject only to the requirements of 40 CFR 63.6640(f).

Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters at major sources of HAPs. EPA has published various actions regarding implementation of this rule as detailed following:

- September 13, 2004 EPA promulgated standards for major sources
- June 19, 2007 US Court of Appeals for the district of Columbia vacated and remanded the standards
- March 21, 2011 EPA promulgated new standards
- May 18, 2011 EPA published notice of delay of the effective dates until judicial review or EPA reconsideration is completed, whichever is earlier
- January 9, 2012 DC Circuit Court vacated EPA's May 18, 2011, stay of the regulation. EPA will use its enforcement discretion to send new and existing sources a "no action assurance letter" indicating that they are not required to submit administrative notifications to permitting agencies signifying that they are subject to the Boiler MACT as issued on March 21, 2011.
- July 18, 2012 EPA announced that it is extending the "No Action Assurance" issued on March 13, 2012, to apply to the deadline for submitting the "Notification of Compliance Status" regarding initial tune-ups in the final Boiler Area Source rule. The agency emphasized that this applies only to the requirement to submit the Notification of Compliance Status for the initial tune up and not to any other provisions of the area source rule. EPA also announced that it is amending the expiration date of the March 13, 2012, "No Action Assurance" so that it will expire when the final Boiler Area Source reconsideration rule is issued and becomes effective or December 31, 2012, whichever is earlier.

Section 112(j) of the Clean Air Act addresses situations where EPA has failed to promulgate a standard as required under 112(e) (1) and (3). 112(j) requires case-by-case MACT determination applications to be submitted to the permitting authority within specified time frames. Since 112(j) appears to only address situations where EPA has failed to promulgate standards and not situations in which complete rules are subsequently vacated, confusion existed as to the requirements for these sources. On March 30, 2010, EPA proposed a rule to amend 112(j) to clarify what applies under 112(j). In the proposed rule, EPA clarifies that the intent was that vacated sources should be treated similar to sources where EPA has failed to promulgate a standard. The rule, as proposed, will require case-by-case MACT applications to be submitted to the permitting authority within 90 days after promulgation of these amendments or by the date which the source's permitting authority requests such application. Compliance with this subpart will be determined based on the requirements of the amended 112(j).

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 greater than major source levels.

The turbines are not subject to CAM monitoring since the low-NOx combustors are not considered add-on control devices.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable At This Time]
This facility will not process or store more than the threshold quantity of any regulated substance (Section 112r of the Clean Air Act 1990 Amendments).More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
This facility is an affected source, and is not subject to any of the exemptions under 40 CFR 72.7, 72.8 or 72.14. 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, U.S. EPA, has confirmed that this requirement was for the benefit of the regulating agency (Oklahoma DEQ), which can waive this requirement and has done so. The applicant has submitted their acid rain permit application.

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

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
The facility shall comply with the emission monitoring and reporting requirements of this Part.

Acid Rain, 40 CFR Part 76 (NO_X Requirements) [Not Applicable]
This part provides for NO_X limitations and reductions for coal-fired utility units only.

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

Tier Classification And Public Review

This application has been determined to be Tier II based on the request for a construction permit for a “significant” modification for an existing major source.

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

Public review of the application and permit are required. The applicant published the "Notice of Filing a Tier II Application" on October 31, 2012, in the *The Anadarko Daily News,* a daily newspaper printed in Caddo County. The notice stated that the application was available for public review at the Anadarko Public Library or at the Air Quality Division's main office. The applicant also published a "Notice of Tier II Draft Permit" on November 29, 2012, in *The Anadarko Daily News*. The permit has been approved for concurrent public and EPA review. No comments were received from the public, but some comments were received from EPA Region VI.

COMMENT 1: *In the Permit Memorandum (Preliminary Determination Summary), it does not appear that the State provided a detailed administrative record documenting appropriate best available control technology (BACT) determinations for the emissions of carbon monoxide from the boiler #3.*

In particular, there is no comparison of emission rates and controls permitted at other similar source types. Please ensure that the permit record includes the State's rationale for the BACT determinations, such as a comparison of your BACT limits to the limits in other PSD/NSR permits for similar source types, and an analysis of the technical and economic feasibility of available control technologies.

Response: The comparison of the limits in this permit with other similar facilities was on Page 15 of the Memorandum, and the rationale was discussed on Page 14. It is noted that a single other facility has had a similar permitting action recently, therefore, the table is rather small and easily overlooked.

COMMENT 2: *Page 4 of the Permit Memorandum states that "[g]reenhouse gas emissions are not expected to be affected by the project." We would suggest that ODEQ provide a numerical analysis to document any increase of GHG pollutant or any decrease in GHG pollutants for the permitting record.*

Response: According to the factors in 40 CFR Part 98, GHG emissions are a function of fuel type and usage. Since fuel usage is projected to remain constant, GHG emissions will also remain constant. The application has projected fuel usage to remain approximately identical for subsequent years. The requirements for recordkeeping when using "projected actual emissions" are already stated in OAC 252:100-8-36.2(c). The GHG emissions have been added to the tables on Page 5.

COMMENT 3: *Page 5 of the Permit Memorandum states that the maximum heat input to Boiler 3 will be maintained at 8,111,461 MMBtu per year. Please explain why the heat input is being maintained if the projected fuel use is different after the modification occurs.*

Response: The projected fuel usage following the project is identical to the fuel usage of the baseline years (2008-2009). There is no change projected. While such projections may be of questionable reliability (hence the recordkeeping requirement mentioned in the response to Comment 2), the facility cannot be deemed to have exceeded projections until the time frames have passed.

COMMENT 4: *Page 12 of the Permit Memorandum states that "the CO emission limit set for installations with good combustion practices BACT were 0.15 lb/MMBTU, which is double the proposed level in this application." Did PSO propose a BACT limit of 0.075 lb/MMBtu in the application. However, Page 15 of the Permit Memorandum appears to contradict this statement by showing under "Step 5 – Selection of BACT" that the proposed CO limit for the permit is 0.15 lb/MMBTU. Please address this discrepancy.*

Response: The proposed post-project emission rate had been changed following initial submittal, and it was an oversight on our part not to have deleted the mention of "double the proposed level in this application." That typographical error has been corrected on Page 12.

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

This facility is not located within 50 miles of the Oklahoma border.

Inspection
A Full Compliance Evaluation was conducted on May 22, 2012, by Ron Ingram of the Compliance Section. No violations were noted in the FCE.

Fees Paid
Part 70 permit construction permit application fee of $5,000 and Title V significant modification fee of $1,000 (paid June 28, 2007).

SECTION XI. SUMMARY

The facility has demonstrated the ability to comply with the requirements of the several air pollution control rules and regulations. There are no active Air Quality compliance and enforcement issues concerning this facility that would prohibit issuance of this modified operating permit. Issuance of the construction permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Public Service Company of Oklahoma (PSO)
Southwestern Power Station **Permit No. 2011-228-C (M-1)(PSD)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on October 23, 2012. The Evaluation Memorandum dated January 15, 2013, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Points of emissions and emissions limitations and standards for each point:
[OAC 252:100-8-6(a)(1)]

EUG 1: Steam Generators are "grandfathered" (pre-May 31, 1972 construction) equipment. There are no hourly or annual emission limits applied to the following units under Title V, but they are limited to the equipment as it presently exists.

EU ID#	Point ID#	EU Name, Model	MMBTUH	MW Gross	Serial No.	Const. Date
1N	1N	Babcock/Wilcox, S-1853	482**	42	17210	Jan. 1952*
1S	1S	Babcock/Wilcox, S-9747	482**	42	17209	Jan. 1952*
2	2	Babcock/Wilcox, S-9742	940**	84	17438	Feb. 1954*
3	3	Babcock/Wilcox, RB-426	3,290**	332	BW21718	May 1967*

*Date is actual start-up date, not construction start date due to the lack of records available.
**Actual Full Load used by System Operations

a. The above units are authorized to operate 8,760 hours per year.
b. Following installation of Low-NOx burners and overfire air on Unit 3, NOx emissions from Unit 3 shall not exceed 0.45 lb/MMBTU, 30-day rolling average, and CO emissions shall not exceed 0.15 lb/MMBTU, 30-day rolling average.

EUG 2: Tank VOC emissions are insignificant based on existing equipment and do not have a specific limitation.

EU ID#	Point ID#	Contents	Capacity		Construction Date
			Barrels	Gallons	
TANK1	T-1	Fuel Oil	50,000	2,100,000	1952
TANK2	T-2	Fuel Oil	50,000	2,100,000	1954
TANK3	T-3	Diesel Fuel	2,000	84,000	1954
TANK4	T-4	Condensate	400	16,800	1980*
TANK5	T-5	Lube Oil	71.5	3,000	1954
TANK6	T-6	Lube Oil	71.5	3,000	1966
TANK7	T-7	Lube Oil	71.5	3,000	1966
TANK8	T-8	Condensate	100	4,200	1997**
TANK9	T-9	Condensate	2	84	2010

*This tank is owned and operated by the natural gas supplier, Enogex, Inc.
****** This tank is owned and operated by the natural gas supplier, Oklahoma Gas and Transmission.

EUG 3: The emergency generator qualifies as an insignificant activity since it operates less than 500 hours per year. Therefore, there are currently no emission limitations. Standards of NESHAP Subpart ZZZZ will take effect upon the compliance date for those standards.

EU ID#	Point ID#	EU Name/Model	hp	Serial No.	Const. Date
EG1	EG1	**Caterpillar 3500**	2,847	4XF00410	1995

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

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

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

<u>General Compliance Requirements</u>
vi. § 63.6605 What are my general requirements for complying with this subpart?

Testing and Initial Compliance Requirements

vii. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?

viii. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

Continuous Compliance Requirements

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

Notifications, Reports, and Records

x. § 63.6650 What reports must I submit and when?

xi. § 63.6655 What records must I keep?

xii. § 63.6660 In what form and how long must I keep my records?

Other Requirements and Information

xiii. § 63.6665 What parts of the General Provisions apply to me?

xiv. § 63.6670 Who implements and enforces this subpart?

xv. § 63.6675 What definitions apply to this subpart?

EUG 4: Fugitive Emissions Fugitive emissions at this facility are negligible.

EUG 5. Combustion Turbines. Emission limits and standards for Emission Units (EUs) 4 and 5 include but are not limited to the following:

Each of the Two Combustion Turbines are limited to the following:			**The Two Turbines Combined Are Limited to the Following Sums:**
Pollutant	**lb/hr** [1]	**ppmvd**[2]	**TPY** [3]
NO_X	35.00	9	84.59
CO	59.00	25	142.59
VOC	2.00	--	4.00
SO_2	15.00	--	30.00
PM_{10} [4]	10.00	--	20.00
H_2SO_4	0.12	--	0.24

[1] Three-hour rolling average, based on the arithmetic average of three contiguous one-hour operating periods.
[2] All concentrations are corrected to 15% O_2, per turbine.
[3] Twelve-month rolling total.
[4] PM_{10} limits are for filterable plus condensable PM_{10}.

a. The turbines shall only be fired with pipeline-quality natural gas.
[OAC 252:100-31 & 8-34]

b. The turbine units shall be equipped with dry low-NO_X burners. [OAC 252:100-8-34]

c. The turbines shall burn no more than a total of 4,228 MMSCFY (combined total, based on an average heating value of 1,020 Btu/CF) of pipeline-grade natural gas per 12-month rolling period. [OAC 252:100-8-5]

d. During start-up, the turbines shall not operate more than 2-hours outside the pre-mix mode. During normal operations, the turbines shall not operate below 60 percent of the rated turbine load. Excess emissions that result from upset conditions, malfunctions or maintenance are exempt from the limits established above if the owner or operator complies with the requirements of OAC 252:100-9-3.1 and OAC 252:100-9-3.3(c) and demonstrates that the conditions of OAC 252:100-9-3.3(a)(1)-(9) or OAC 252:100-9-3.3(b)(1)-(7) apply. For an excess emission to be deemed to result from "upset" conditions, it must result from unforeseeable circumstances or circumstances beyond the control of the operator (e.g., lightning strikes on equipment). [OAC 252:100-9]

e. Each turbine is subject to the federal New Source Performance Standards (NSPS) for Stationary Gas Turbines, 40 CFR 60, Subpart GG, and shall comply with all applicable requirements. [40 CFR §60.330 to §60.335]

   i. 60.332: Standard for nitrogen oxides
   ii. 60.333: Standard for sulfur dioxide
   iii. 60.334: Monitoring of operations
   iv. 60.335: Test methods and procedures
   v. Monitoring of the fuel sulfur content is not required if the permittee can demonstrate that the gaseous fuel meets the definition of "natural gas" with a maximum total sulfur content of less than 20 grains/100 SCF (680 ppmw or 338 ppmdv) or less using either a current valid purchase contract, tariff sheet, or transportation contract or representative fuel sampling. Monitoring of fuel nitrogen content under NSPS Subpart GG shall not be required unless the permittee claims an allowance for fuel bound nitrogen.

f. During startups and shutdowns alternate emission limits apply to the combustion turbines. Startup events shall not exceed two hours per turbine. Shutdown events shall not exceed one hour per turbine. Emission limits for NO_x and CO during startups and shutdowns shall be as listed in Specific Condition No. 1.f. The following definitions apply.

Startup: Startup for each gas turbine begins when fuel is supplied to the Gas Turbine and combustion is initiated. Startup ends when the gas turbine reaches DLN mode (as direct by the control system).
Shutdown: Shutdown begins when the turbine exits the DLN mode. Shutdown ends with the termination of fuel flow to the turbine.
Cold Start: A startup beginning more than 24 hours after the same unit shutdown.
Warm Startup: A startup beginning less than 24 hours after the same unit shutdown.
For startup and shutdown operations, the emission limitations for each combustion turbine are listed below:

Event	Maximum Duration (hr)	NO_x Emissions (lbs)	CO Emissions (lbs)
Startup (cold)	2	372	627
Startup (warm)	2	114	192
Shutdown	1	21	35

EUG 6: The High Pressure Gas Yard heater qualifies as an insignificant activity. Therefore, there are no emission limitations.

EU ID#	Point ID#	EU Name/Model	MMBTUH	Const. Date
6	6	High-pressure gas yard heater	5.6	2009

2. The boilers shall only be fueled with pipeline-quality natural gas or No. 2 fuel oil with a maximum sulfur content of 0.7% by weight except for Boiler No. 3. No. 3 boiler shall only be fueled with pipeline-quality natural gas. A greater amount of fuel oil may be used in terms of operating more than one boiler at a time, but the fuel oil weight percent sulfur as burned must be proportionately less than 0.7% sulfur for Boilers No. 1N, No. 1S, and No. 2, respectively, depending on boiler and system operating requirements. The emergency generator shall be fueled with diesel with a maximum sulfur content of 0.7% by weight. [OAC 252:100-31]

3. The units shall be only be operated to burn fuel oil in one unit at a time. No combination of two units shall be operated to burn fuel oil concurrently. [OAC 252:100-31]

4. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements including the following:

   a. SO_2 actual emissions equal or less than allowances held.
   b. Report quarterly emissions to EPA per 40 CFR 75.
   c. Conduct RATA tests per 40 CFR 75.
   d. Maintain a QA/QC plan for the monitoring system.

5. All VOC tanks constructed after July 1, 1972, with a capacity of 400 gallons or more and storing a liquid which has a vapor pressure of 1.5 psia or greater shall be equipped with a permanent submerged fill pipe or an organic vapor recovery system. [OAC 252:100-37-15]

6. The permittee shall keep operation and maintenance (O&M) records for those "grand-fathered" emission units identified in EUG 1, which have not been modified and for those replacement or additional engines/turbines which do not conduct quarterly testing. Such records shall at a minimum include the dates of operation, and maintenance, type of work performed, and the increase, if any, in emissions as a result. [OAC252:100-8-6(a)(3)(B)]

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

   a. Analysis of the sulfur content for each shipment of No. 2 fuel oil and diesel fuel.
   b. O&M records for each boiler.
   c. Usage of natural gas, No. 2 fuel oil, and diesel fuel (monthly and 12-month rolling total).
   d. Operating hours of each emergency generator (monthly and 12-month rolling total).
   e. Operating hours for each boiler (monthly and 12-month rolling total).
   f. RATA test results.
   g. Records as required by 40 CFR Part 63, Subpart ZZZZ.
   h. Opacity records required by Specific Condition 9.
   i. Records as required by NSPS Subpart GG.

j. Records as required by 40 CFR Part 75.

8. The following records shall be maintained on site to verify insignificant activities. Insignificant activities which are also trivial activities do not require record keeping. [OAC 252:100-43]

   a. Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power or for peaking power service not exceeding 500 hours/year: hours of operation. Upon the compliance date for standards of 40 CFR Part 63, Subpart ZZZZ, affecting the stationary engine, those standards will supersede this requirement.
   b. For storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature: records of capacity of the tanks, and contents.
   c. Surface coating and degreasing operations which do not exceed a combined total usage of more than 60 gallons/month of coatings, thinners, clean-up solvents, and degreasing solvents at any one emissions unit: amount of solvent/coatings used (annual total).
   d. For activities (except for trivial activities) that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions or a surrogate measure of the activity (annual total).

9. When fuel oil is burned in the boilers or diesel oil is burned in the generators for more than a 24-hour period, the permittee shall conduct visual observations of the opacity from exhaust stacks for each subsequent 24-hour period. If any visible emissions are detected, then the permittee shall conduct a six-minute opacity reading by a certified observer in accordance with EPA Reference Method #9. The permittee shall maintain records of the date and time of each observation, stack or emission point identification, operational status of the emission unit, observed results and conclusions, and RM 9 results. [OAC 252:100-43]

10. No later than 30 days after each anniversary date of the issuance of the original Title V operating permit (June 21, 1999), 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)]

    a. Following submittal of an Annual Compliance Certification for the period of June 21 to March 1, March 1 of each year may be used as the anniversary date for Annual Compliance Certifications.
    b. Following submittal of a Semi-Annual Monitoring Report either for the period of June 22 to August 31 or for the period of December 22 to March 1, March 1 of each year may be used as the anniversary date for Semi-Annual Monitoring Reports.

11. The permittee is authorized to evaporate non-hazardous boiler chemical cleaning waste (BCCW), and to combust on-spec used oil. The BCCW and on-spec used oil may be either generated on-site or from other PSO facilities. These operations may be conducted on an as-needed basis. The total volume of BCCW and on-spec used oil and the associated emissions with evaporating/combusting them shall be reported with the annual emissions inventory. [OAC 252:100-31]

12. Unit 3 in EUG 1 is subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and shall comply with all applicable requirements including but not limited to the following: [40 CFR §§ 51.300-309 & Part 51, Appendix Y]

a. Affected facilities. The following sources are affected facilities and are subject to the requirements of this Specific Condition, the Protection of Visibility and Regional Haze Requirements of 40 CFR Part 51, and all applicable SIP requirements:

EU ID#	Point ID#	EU Name	Heat Capacity (MMBTUH)	Construction Date
3	3	Babcock/Wilcox, RB-426	3,290	May 1967

b. Each existing affected facility shall install and operate the SIP approved BART as expeditiously as practicable but in no later than five years after approval of the SIP incorporating the BART requirements.

c. The permittee shall apply for and obtain a construction permit prior to modification of the boilers. If the modifications will result in a significant emission increase and a significant net emission increase of a regulated NSR pollutant, the applicant shall apply for a PSD construction permit.

d. The affected facilities shall be equipped with the following current combustion control technology, as determined in the submitted BART analysis, to reduce emissions of NOX to below the emission limits below:
   i. Low-NOX Burners,
   ii. Overfire Air, and

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

f. Within 60 days of achieving maximum power output from each affected facility, after modification or installation of BART, not to exceed 180 days from initial start-up of the affected facility the permittee shall comply with the emission limits established in the construction permit. The emission limits established in the construction permit shall be consistent with manufacturer's data and an agreed upon safety factor. The emission limits established in the construction permit shall not exceed the following emission limits:

EU ID#	Point ID#	NOX Emission Limit	Averaging Period
3	03	0.45 lb/MMBTU	30-day rolling

g. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da, for units modified after March 2005.

h. After installation of the BART, the affected facilities shall only be fired with natural gas.

i. Within 60 days of achieving maximum power output from the boiler, after modification of the boiler, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with BART emission limits for the affected facilities.[OAC 252:100-8-6(a)]

  i. The permittee shall conduct NOX, CO, and VOC testing on the boilers at 60% and 100% of the maximum capacity. NOX and CO testing shall also be conducted at least one additional intermediate point in the operating range.
  ii. Performance testing shall be conducted while the units are operating within 10% of the desired testing rates. A testing protocol describing how the testing will be performed shall be provided to the AQD for review and approval at least 30 days prior to the start of such testing. The permittee shall also provide notice of the actual test date to AQD.
  iii. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

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 10:	Determination of Carbon Monoxide Emissions from Stationary Sources.
Method 25/25A:	Determination of Non-Methane Organic Emissions From Stationary Sources.

13. The permittee shall apply for a modification to the facility Air Quality operating permit within 180 days following installation of modifications of the boiler as described in this permit.

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. 2011-228-C (M-1)(PSD)

Public Service Company of Oklahoma (PSO),

having complied with the requirements of the law, is hereby granted permission to construct modifications to the Southwestern Power Station located in Section 10, Township 7N, Range 11W, near Anadarko, Caddo County, Oklahoma, subject to standard conditions dated July 21, 2009, and specific conditions, both attached.

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

Division Director, Air Quality Division | **Date**

Air Quality Division

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

Public Service Company of Oklahoma (PSO)
Attn: Mr. William Hildeson
Senior Environmental Specialist
1201 Elm Street, Suite 800
Dallas, TX 75202

SUBJECT: Permit No. **2011-228-C (M-1)(PSD)**
Southwestern Power Station
Location: Washita, Caddo County

Dear Mr. Hildeson:

Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to the certain standards 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.

If you have any questions, please refer to the permit number above and contact me at David.Schutz@deq.state.ok.us or at (405) 702-4198.

Sincerely,

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

Enclosures

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

SECTION I. DUTY TO COMPLY

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

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

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

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

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

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

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

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

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SECTION IV. COMPLIANCE CERTIFICATIONS

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

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

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

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

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

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

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

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

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

SECTION VI. PERMIT SHIELD

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

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

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

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

SECTION VIII. TERM OF PERMIT

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

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

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

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

SECTION IX. SEVERABILITY

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

SECTION X. PROPERTY RIGHTS

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

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

SECTION XI. DUTY TO PROVIDE INFORMATION

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

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

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

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

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

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

SECTION XII. REOPENING, MODIFICATION & REVOCATION

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

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

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

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

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

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

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

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.
[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.
[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

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

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

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

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

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

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

SECTION XV. RISK MANAGEMENT PLAN

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

SECTION XVI. INSIGNIFICANT ACTIVITIES

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

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

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

SECTION XVII. TRIVIAL ACTIVITIES

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

SECTION XVIII. OPERATIONAL FLEXIBILITY

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

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

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

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

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

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

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

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

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

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

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

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

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

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

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;

(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

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

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

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

SECTION XXII. CREDIBLE EVIDENCE

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