OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **November 22, 2004**

TO: Dawson Lasseter, P.E., Chief Engineer, Air Quality Division

THROUGH: David Schutz, P.E., New Source Permits Section
John Howell, E.I., Existing Source Permits Section

THROUGH: Peer Review

FROM: Ing Yang, P.E., New Source Permits Section

SUBJECT: Evaluation of Permit Application No. **97-137-C (M-3) (PSD)**
OG&E Electric Services
Horseshoe Lake Generating Station
Section 14, T12N, R1EIM, Oklahoma County
NE 36^{th} and Luther Road, Harrah, Oklahoma 73045

SECTION I. INTRODUCTION

Oklahoma Gas & Electric Company (OG&E) has proposed to expand operating hours of two existing GE-LM6000PC 45MW natural gas-fired simple-cycle turbines (Units 9 and 10) at the Horseshoe Lake Generating Station in Harrah, Oklahoma (SIC Code 4911). A decrease in Unit 8's operation will accompany the change to avoid triggering the PSD significance level for NOx. This modification is subject to PSD as a result of significant net increases in potential emissions of carbon monoxide (CO). The project will enable OG&E to produce additional electricity during summer and winter peaking periods in order to meet growing customer demands. The facility is located in an attainment area. The requested change in operation of Units 9 and 10 is considered a Prevention of Significant Deterioration (PSD) modification due to net emissions increases in regulated pollutants above significance levels. Therefore, this modification will go through a Tier II review process.

SECTION II. FACILITY DESCRIPTION

The facility consists of three (3) natural gas-fired utility boiler units, one (1) combined-cycle gas turbine, two (2) simple-cycle combustion turbine generators (CTG), two (2) auxiliary boilers, one (1) diesel emergency generator and one (1) house heat boiler. The boilers were originally constructed in the 1950s and 1960s. These units have been designated Unit 6, 7, and 8. Unit 7 is a combined-cycle unit which includes a natural gas-fired turbine. The electric generating boilers Units 6 and 7 use pipeline grade natural gas as a primary fuel and #2 fuel oil as a secondary fuel. Unit 8, two gas turbines and the auxiliary boilers utilize pipeline natural gas as a primary fuel. Previously, the facility was also allowed to combust company-generated non-hazardous materials for energy recovery and waste reduction. These may include used oil, used solvents, corrosion inhibitors, on-line cleaning solution, and antifreeze.

The turbines use water injection for the control of NOx. The injected water acts as a heat sink which in turn lowers the combustion zone temperature, and therefore reduces thermal NOx formation. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone.

SECTION III. EQUIPMENT

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

EUG 1. Electric Generating Boilers and Turbine

EU ID#	Make	Heat Capacity (MMBTUH)	Serial #	Installed Date
2-B-01, Unit 6	Babcock & Wilcox	1,740	RB-260	1958
2-B-02, Unit 7	Babcock & Wilcox Boiler	2,379	RB-381	1963
2-B-02, Unit 7	GE Gas Turbine	511	127744	1963
2-B-03, Unit 8	Combustion Engineering	3,960	20754	1968

EUG 2. House Heat Boiler

EU ID#	Make/Model	Heat Capacity (MMBTUH)	Serial #	Manufactured Date
2-B-04	Cleaver Brooks/CB657-350	14.65	L-53234	1971

EUG 3. Electric Generating Gas Turbines

EU ID#	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
3-B-01, Unit 9	GE/LM6000PC Sprint	550	308771	2000
3-B-02, Unit 10	GE/LM6000PC Sprint	550	265046	2000

EUG 4. Auxiliary Boilers

EU ID#	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
4-B-01	Precision Boiler/ FPH62-100-P4200N	3.4	B000020B	2000
4-B-02	Precision Boiler/ FPH62-100-P4200N	3.4	B000020	2000

EUG 5. Emergency Diesel Generator

EU ID#	Make/Model	hp	Serial #	Installed Date
5-B	General Motor/MP36A	2,875	63399	1966

EUG 6. Storage Tanks

Point and EU ID#	Capacity (gallons)	Material Stored	Installed Date
6-B-01	2,310,000	Fuel Oil	1958
6-B-02	2,310,000	Fuel Oil	1974
6-B-03	230,000	Used Oil	1962
6-B-10	500	Diesel Fuel	1985
6-B-11	1,058	Gasoline	1992
6-B-12	1,058	Diesel Fuel	1992
6-B-13	300	Diesel Fuel	1992
6-B-14	2,730	Diesel Fuel	1963
6-B-15	420	Kerosene	1992

SECTION IV. EMISSIONS

Criteria Pollutants

Emission estimates for electric generating units (Unit 6, 7, and 8) reflect continuous operation based on two scenarios, fired on natural gas and fuel oil. Emissions from natural gas combustion are calculated based on AP-42 (7/98), Tables 1.4-1 and 1.4-2. Emissions from fuel oil combustion are calculated based on AP-42 (9/98), Tables 1.3-1 and 1.3-3. Only Unit 6 and 7 are capable of burning fuel oil. Fuel consumption for Unit 6 and Unit 7 are 10,864 gal/hr and 11,766 gal/hr, respectively. The sulfur content of fuel oil is 0.5 weight percent. Emissions from the Unit 7 gas turbine are estimated based on AP-42 (4/00), Tables, 3.1-1, and 3.1-2a. For the gas turbines (Units 9 and 10), emission estimates of NO_X, CO, and PM_{10} are based on manufacturer's data and emission estimates of VOC and SO_2 based on AP-42 (4/00), Table 3.1-2a. The calculations are based on the total of 4,000 operating hours per year for turbines. The emissions from the natural gas-fired auxiliary boilers (4-B-01 and 4-B-02) are based on AP-42 (7/98), Tables 1.4-1 and 1.4-2, and on operation of 1,000 hours per year for each boiler. The emissions from the natural gas/fuel oil fired house heat boiler (2-B-04) are estimated based on AP-42 (9/98), Table 1.3-1 and 1.3-3, and on operation of 3,000 hours per year. The diesel engine is for emergency use only. Emissions from the diesel generator are estimated based on operating 500 hours per year using AP-42 (10/96), Table 3.4-1. Emissions from tanks are estimated based on EPA's TANKS modeling program. Emissions from Units 6 and 7 are estimated based on firing fuel oil only.

Emissions from Electric Generating Boiler Units Fired with Natural Gas

EU ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Unit 6	487.2	2,134	146.2	640.2	9.57	41.92	1.04	4.57	13.22	57.92
Unit 7	829.6	3,634	241.0	1,055	14.15	62.01	3.167	13.86	21.45	93.96
Unit 8	1,108	876.9	332.6	52.5	21.78	12.04	2.38	1.42	30.10	16.63
Subtotal	2,425	6,645	719.8	1747.7	45.50	115.97	6.59	19.85	64.77	168.51

Emissions from Electric Generating Boiler Units Fired with Fuel Oil

EU ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Unit 6	434.0	1,901	46.17	202.2	7.017	30.73	724.8	3,175	72.16	316.0
Unit 7	683.8	2,995	97.25	426.0	9.490	41.55	870.7	3,814	89.88	393.7
Subtotal	1,118	4,896	143.4	628.2	16.50	72.28	1,595	6,989	162.0	709.7

Emissions from Electric Generating Gas Turbines

EU ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Unit 9	50.0	78.0	77.0	120.0	5.5	8.60	5.5	0.52	3.85	6.02
Unit 10	50.0	78.0	77.0	120.0	5.5	8.60	5.5	0.52	3.85	6.02
Subtotal	100.0	156.0	154.0	240.0	11.0	17.20	11.0	1.03	7.7	12.04

Emissions from House Heater Boiler

EU ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2-B-04	2.09	3.14	1.19	1.79	0.08	0.12	7.42	11.13	0.21	0.31
Subtotal	2.09	3.14	1.19	1.79	0.08	0.12	7.42	11.13	0.21	0.31

Emissions from Auxiliary Boilers

EU ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
4-B-01	0.34	0.17	0.29	0.14	0.019	0.01	0.002	0.001	0.026	0.013
4-B-02	0.34	0.17	0.29	0.14	0.019	0.01	0.002	0.001	0.026	0.013
Subtotal	0.68	0.34	0.58	0.28	0.038	0.02	0.004	0.002	0.052	0.026

Emissions from the Diesel Generator

EU ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
5-B	69.00	17.25	15.81	3.95	2.01	0.50	11.5	2.88	2.01	0.50
Subtotal	69.00	17.25	15.81	3.95	2.01	0.50	11.5	2.88	2.01	0.50

Emissions from the Fuel Oil Tanks

EU ID#	Capacity (gallon)	Material Stored	lb/hr	TPY
6-B-01	2,310,000	Fuel Oil	0.055	0.24
6-B-02	2,310,000	Fuel Oil	0.055	0.24
Subtotal	---	---	0.110	0.48

Total Emissions

Source	NO_x		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Electric Generating Boilers	2,424.8	6,644.9	719.8	1747.7	45.5	115.97	1,597	6,990	192.1	726.3
Gas Turbines	100.0	156.0	154.0	240.0	11.0	17.20	11.0	1.04	7.7	12.04
House Heat Boiler	2.09	3.14	1.19	1.79	0.08	0.12	7.42	11.13	0.21	0.31
Auxiliary Boilers	0.68	0.34	0.58	0.28	0.038	0.02	0.004	0.002	0.052	0.026
Emergency Generator	69.00	17.25	15.81	3.95	2.01	0.50	11.5	2.88	2.01	0.50
Storage Tanks	---	---	---	---	0.11	0.48	---	---	---	---
Total Emissions	**2,597**	**6,822**	**891**	**1,994**	**58.7**	**134.3**	**1,627**	**7,005**	**202.1**	**739.2**

Emissions of Hazardous Air Pollutants (HAPs) and Toxic Air Contaminants (TACs)

HAPs emissions that may exceed de minimis level are from electric generating boilers (Units 6, 7, and 8). HAPs emissions from other emission units are insignificant. Emissions of benzene, formaldehyde, and pentane reflect continuous operation of the boilers and are calculated based on the emission factors from AP-42 (7/98), Table 1.4-3. Based on the EPRI (Electric Power Research Institute) Emission Factors Handbook (2002), OG&E has used a corrected emission factor of 0.42 lbs/Tbtu for hexane emissions. Emissions from other speciated HAPs are not listed because their emissions are much lower than the de minimis level.

The facililty may incinerate corrosion inhibitors used in Units 9 or 10 in boilers Units 6 or 7. This waste consists of approximately 900 ppm sodium nitrite and 180 ppm potassium hydroxide. Expected emissions from the incineration will be sodium nitrite and potassium hydroxide. The emissions are estimated by assuming that all sodium nitrite and potassium hydroxide in the waste are emitted. Annual waste incinerated and the maximum incineration rate shall be such that emissions do not exceed de minimis levels set forth in OAC 252:100-41.

HAPs and TACs Emissions from the Electric Generating Boilers and Turbines

Pollutant	CAS#	Toxic Category	Potential	
			lb/hr	TPY
Benzene*	71-43-2	A	0.028	0.086
Formaldehyde*	50-00-0	A	1.24	3.25
Hexane*	110-54-3	C	0.003	0.015
Pentane	109-66-0	C	21.00	92.00
Sodium Nitrite	7632000	A	0.56	0.034
Potassium Hydroxide	1310583	B	0.11	0.0068

Pollutants followed by an asterisk are HAPs.

SECTION V. INSIGNIFICANT ACTIVITIES

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

1. * Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generation or for peaking power service not exceeding 500 hours/year. One 2,875-hp diesel emergency power generator is located on-site.

2. * Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, average over a 30-day period. There is one 1,058 gallon gasoline tank located on-site for this purpose.

3. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTU/hr heat input (commercial natural gas). There are two (2) 80,000 Btu/hr natural gas fired heaters.

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. There are four (4) diesel tanks and one (1) kerosene tank located on-site.

5. Cold degreasing operations utilizing solvents that are denser than air. Cold degreasing occurs in the maintenance shop and the turbine floor.

6. Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes. Some operations are conducted at the facility. Welding and soldering are conducted as part of plant maintenance operations; since maintenance is a "Trivial Activity", no recordkeeping will be required.

7. Hazardous waste and hazardous materials drum staging areas. The facility maintains a drum storage area.

8. Sanitary sewage collection and treatment facilities other than incinerators and Publicly Owned Treatment Works (POTW). Stacks or vents for sanitary sewer plumbing traps are also included. This facility contains a tile field and lift stations associated with sanitary sewage collection and treatment.

9. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas. There is a chemical laboratory at the site.

10. 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. The facility performs small amounts of hand wiping and spraying of solvents.

11. * Activities that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant. None listed but may be used in the future.

SECTION VI. PSD REVIEW

PSD review requires emissions netting that determines “net emissions increase” consisting of two additive components:

a. any increases in actual emissions from a particular physical change or change in method of operation at a stationary source.
b. any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

NO_x Emissions in TPY

Unit #	**Current Actual Emissions**	**Future Projected Actual, Taking into Account Permit Limits**
2-B-03, Unit 8 Boiler	997.91	876.6
	Contemporaneous Emissions Increases/Decreases	
3-B-01, Unit 9 Turbine	0	78.0
3-B-02, Unit 10 Turbine	0	78.0
Net Emissions Increase	34.95	
NOx Emissions	**1,032.86**	**1,032.86**

CO Emissions in TPY

Unit #	**Current Actual Emissions**	**Future Projected Actual, Taking into Account Permit Limits**
2-B-03, Unit 8 Boiler	59.77	52.52
	Contemporaneous Emissions Increases/Decreases	
3-B-01, Unit 9 Turbine	0	120
3-B-02, Unit 10 Turbine	0	120
Net Emissions Increase	232.75	
CO Emissions	**292.52**	**292.52**

VOC Emissions in TPY

Unit #	**Current Actual Emissions**	**Future Projected Actual, Taking into Account Permit Limits**
2-B-03, Unit 8 Boiler	13.7	12.04
	Contemporaneous Emissions Increases/Decreases	
3-B-01, Unit 9 Turbine	0	8.6
3-B-02, Unit 10 Turbine	0	8.6
Net Emissions Increase	15.54	
VOC Emissions	**29.24**	**29.24**

SO_2 Emissions in TPY

Unit #	**Current Actual Emissions**	**Future Projected Actual, Taking into Account Permit Limits**
2-B-03, Unit 8 Boiler	1.62	1.42
	Contemporaneous Emissions Increases/Decreases	
3-B-01, Unit 9 Turbine	0	.52
3-B-02, Unit 10 Turbine	0	.52
Project Increase	.84	
SO2 Emissions	**2.46**	**2.46**

PM_{10} Emissions in TPY

Unit #	Current Actual Emissions	Future Projected Actual, Taking into Account Permit Limits
2-B-03, Unit 8 Boiler	18.93	16.63
	Contemporaneous Emissions Increases/Decreases	
3-B-01, Unit 9 Turbine	0	6.02
3-B-02, Unit 10 Turbine	0	6.02
Project Increase	9.74	
SO2 Emissions	**28.67**	**28.67**

PSD Netting Calculations Unit 8, 9 and 10 Combustion Turbines

Pollutant	Unit 8 Baseline Emissions, TPY	* Increase Associated with Project, TPY	** Reductions from Limiting Unit 8, TPY	Net Emissions Increase, TPY	PSD Significant Rates, TPY	PSD Review Triggered
NO_x	997.91	156.0	121.05	34.95	40	No
CO	59.77	240.0	7.25	232.75	100	Yes
VOC	13.70	17.20	1.66	15.54	40	No
PM_{10}	18.93	12.04	2.30	9.74	15	No
SO_2	1.62	1.04	0.20	0.84	40	No

* Total increases associated with project

** Decrease in emissions associated with limiting Unit 8's operation.

In this case, there will be significant emission increase above the PSD significance level for CO from the proposed modification.

<u>Best Available Control Technology (BACT) Demonstration</u>

The emissions of CO exceed the PSD-significant quantities and therefore are subject to BACT review. This BACT determination uses EPA's "top-down" approach described in the *New Source Review Workshop Manual* (10/1990). The first step in this approach is to determine, for the emission unit and pollutant in question, the most stringent control commercially available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the unit in question, then 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, environmental, or economic objections. In addition, if a proposed source meets or betters the most stringent prior BACT determination for similar sources, then BACT is deemed to have been met for the proposed source.

Step 1 - Identify All Control Technologies

Pollutant	Simple Cycle Combustion Turbine Control Technologies
CO	• Catalytic Oxidation • Good Combustion Practices

Step 2 - Technical Feasibility Analysis

Pollutant	Most Stringent RBLC Emission Limit	Control Technology
CO	25 ppmvd @ 15% O_2	Good Combustion Practices

Step 3 - Ranking of Remaining Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Add-on Control Efficiency (%)
CO	Catalytic Oxidation Good Combustion Practices	75-90

Step 4 - Top-Down Evaluation of Control Options

Control options must next be evaluated to determine the most effective control technology. The control technologies are evaluated on the basis of economic, energy, and environmental considerations.

Two applicable CO control techniques have been identified for combustion turbines. One is catalytic oxidation and the other is based on efficient combustion/design technology.

Catalytic oxidation of CO is a technically proven control alternative for combustion turbines; however, it has primarily been used to meet specialized requirements such as Lowest Achievable Emission Rate (LAER), typically in areas that are designated as non-attainment for CO.

The installed capital cost associated with catalytic oxidation is $536,833 and the annualized cost is $194,875 per turbine when firing natural gas. The cost-effectiveness is $2,707 per ton CO removed. These cost impacts are considered excessive.

The CO emission rate under maximum load conditions will be limited to 62.5 ppmvd at 15% O_2 when firing natural gas. A review of EPA's RBLC database indicates that other combustion turbines that utilize natural gas have been issued permits with BACT-based CO emissions in the range of 10 to 42 ppmvd (based upon full load operation). Given the regional air quality conditions and the fact that the predicted maximum impact of CO emissions on the surrounding environment will not be significant, the proposed emission limits are believed to be BACT. There are no adverse economic, environmental or energy impacts associated with the proposed control alternative. Good combustion practices/design is proposed as BACT for CO emissions from the combustion turbines.

Conclusion

A BACT analysis was performed for each affected emission unit based on the "top-down" approach recommended by the EPA. The selected technology for each pollutant for each affected unit represents the most stringent technically and economically feasible control technology considering environmental, energy, and economic impacts. Good combustion practices is proposed as BACT for CO.

Air Quality Impacts

The ISCST3 air dispersion modeling was performed using preprocessed meteorological data based on surface observations taken during the five (5) year period from 1986 through 1991 from Oklahoma City, Oklahoma (1986, 1987, and 1988) and Norman, Oklahoma (1990, and 1991). The National Weather Service Station (NWS), station number for both Oklahoma City and Norman is 13967. The upper air measurements were also taken from Oklahoma City and Norman. An anemometer height of 6.2 meters was used in the modeling. The meteorological data for the year 1989 was not used in this analysis. There is a large gap in data at the end of 1989 for the surface data and upper air data from Oklahoma City. This gap is due to the transfer of the recording station from Oklahoma City to the NWS facility in Norman. Although the data could be substituted using the previously described methods, the ODEQ has previously requested that other data years be substituted.

The ISCST3 model incorporated discrete receptors spaced a maximum of 100 meters apart around the fence line of the Facility. Several different rectangular grids made up of discrete receptors were used in the ISCST3 modeling analysis. The receptors located within 1,000 meters of the fence line were spaced 100 meters apart. These are considered fine spaced receptors. In addition to the fine spaced receptors, a grid spacing of 500 meters was used from 1.0 kilometers out to five (5) kilometers from the proposed facility. These medium spaced receptors were used when determining the location of high impacts so that a fine spaced grid could be designed and located to cover the areas with the highest impacts in the second tier analysis.

A series of modeling analyses for PM_{10}, CO, SO_2, and NOx emissions associated with Unit No.9 and Unit No.10 of the Horseshoe lake Power Plant was performed.

The results of the NOx modeling indicate that there are no significant NOx impacts as a result of the proposed project. The highest predicted annual concentration predicted was 0.738 $\mu g/m^3$.

The results of the PM_{10} modeling indicate that there are no significant PM_{10} impacts as a result of the proposed project. The highest predicted annual concentration was 0.037 $\mu g/m^3$, and the highest predicted 24-hour concentrations was estimated to be 0.254 $\mu g/m^3$.

Five significance model runs for SO_2 using the fence line receptors, the fine receptors, the medium receptors, and the coarse receptors were made. One run was made for each of the five years of meteorological data described above. Based on the runs executed a determination of the maximum impact for the significance analysis was made. Based on. the analysis, no predicted impacts were greater than the PSD significance levels. Therefore, a more detailed analysis for the NAAQS and PSD Increment was not required. The highest estimated concentrations were 0.019 $\mu g/m^3$ for the annual average, 0.155 $\mu g/m^3$ for the 24-hour average, and 0.650 $\mu g/m^3$ for the three hour average.

Five significance model runs for CO using the fence line receptors, the fine receptors, the medium receptors, and the coarse receptors were made. One run was made for each of the five years of meteorological data described above. Based on the runs executed a determination of the maximum impact for the significance analysis was made. Based on the analysis, no predicted impacts were greater than the PSD significance levels. Therefore, a more detailed analysis for the NAAQS and PSD increment was not required. The maximum predicted CO concentrations are 289.51 $\mu g/m^3$ for the-one hour average, and 106.05 $\mu g/m^3$ for the eight-hour average.

Based on the significance modeling results described above, no additional modeling was required. The significance modeling analysis conducted for NOx, PM_{10}, SO_2, and CO all resulted in predicted concentrations for each receptor grid less than the PSD significance levels. Therefore, no modeling analysis for any of the pollutants was made for comparison to the NAAQS, or to determine the amount of increment consumed by the project.

Based on the results of the modeling analysis, the predicted emissions increases due to the project will not result in significant impacts on the air quality of the area around the project. The predicted concentrations of NOx, PM_{10}, SO_2, and CO are all below the significant levels set by the USEPA for PSD emissions.

NO_x Significance Modeling Results

Meteorological Year	Annual Average ($\mu g/m^3$)
1986	0.728
1987	0.660
1988	0.642
1990	0.738
1991	0.704
PSD Significance De Minimis	1.00
Subject To NAAQS/Increment Analysis	No

PM_{10} Significance Modeling Results

Meteorological Year	24-Hr Average ($\mu g/m^3$)	Annual Average ($\mu g/m^3$)
1986	0.251	0.037
1987	0.212	0.033
1988	0.254	0.033
1990	0.162	0.037
1991	0.208	0.036
PSD Significance De Minimis	5.00	1.00
Subject To NAAQS/Increment Analysis	No	No

SO_2 Significance Modeling Results

Meteorological Year	3-Hr Average ($\mu g/m^3$)	24-Hr Average ($\mu g/m^3$)	Annual Average ($\mu g/m^3$)
1986	0.427	0.155	0.018
1987	0.388	0.145	0.018
1988	0.650	0.135	0.017
1990	0.415	0.128	0.019
1991	0.429	0.133	0.016
PSD Significance De Minimis	25.00	5.00	1.00
Subject To NAAQS/Increment Analysis	No	No	No

CO Significance Modeling Results

Meteorological Year	1-Hr Average (μg/m³)	8-Hr Average (μg/m³)
1986	212.93	106.05
1987	268.42	84.58
1988	289.51	82.36
1990	227.42	67.55
1991	257.30	73.55
PSD Significance De Minimis	2,000.00	500.00
Subject To NAAQS/Increment Analysis	No	No

Modeling Results Summary

Air Constituent	Averaging Period	Maximum Modeled Concentration (μg/m³)	Significance De Minimis (μg/m³)	Compliance Demonstrated (Yes/No)
NOx	Annual	0.933	1	Yes
PM_{10}	Annual	0.047	1	Yes
	24-Hr	0.325	5	Yes
CO	1-Hr	371.5	2,000	Yes
	8-Hr	136.1	500	Yes
SO_2	Annual	0.03	1	Yes
	24-Hr	0.22	5	Yes
	3-Hr	0.92	25	Yes

Additional Impacts Analysis

Growth impacts

The purpose of the growth impact analysis is to quantify the possible net growth of the population of the area as a direct result of the project. This growth can be measured by the increase of residents in the area, the additional use and need of commercial and industrial facilities to assist the additional population with everyday services, and other growth, such as additional sewage treatment discharges or motor vehicle emissions.

The net growth associated with this project is zero. OG&E will not be required to hire additional staff to maintain or operate the new units at the Facility. The existing staff at the Horseshoe Lake Station and OG&E Corporate Headquarters will monitor the status of the operations and complete any operating and/or maintenance activities associated with the new turbines and boilers.

Ambient Air Quality Impacts

The purpose of this analysis is to predict the air quality in the area of the project during construction and after commencing operation. This analysis follows the growth analysis by combining the associated growth with the emissions from the proposed project and the emissions from other permitted sources in the area to predict the estimated total ground-level concentrations of pollutants as a result of the project, including construction.

According to the findings in the Growth Analysis, the ambient air quality impacts from additional growth as well as other facilities in the area under construction is zero

Soils and Vegetation Impacts

Within the area of interest of the Horseshoe Lake Facility, the specific Associations of the predominant soils are the Dale-Canadian-Port and the Dougherty-Norge-Teller. The soil classifications within these Associations are silty clay loam to fine sandy loam to clay loam in the Dale-Canadian-Port and loamy fine sand to coarse sandy loam to clay loam within the Dougherty-Norge-Teller. Soil reactivities range between a pH of 6.1 to 8.4 within these Associations.

The main crops typically grown on the soils identified within the area of interest are alfalfa, winter wheat, small grains, grain sorghums, cotton, legumes and grasses. Some soils within the area are used to grow orchards. No sensitive aspects of the soil and vegetation in this area have been identified. As such the secondary National Ambient Air Quality Standards (NAAQS), which establish ambient concentration levels below which it is anticipated that no harmful effects to either soil or vegetation can be expected, are used as the benchmark for this analysis.

The effects of CO on vegetation have undergone only brief laboratory study, thus, its effects on vegetation are somewhat uncertain. Some research indicates that CO exposure may cause the production of ethylene in plant tissue at concentrations of greater than 100 ppm. Since the secondary ambient standards (35 ppm (40,000 $\mu g/m^3$) and 9 ppm (10,000 $\mu g/m^3$) for the 1-hour and 8-hour averages, respectively) will not be exceeded by the Horseshoe Lake Facility, this project should have negligible impacts on nearby soils and vegetation.

Visibility Impairment

Visibility is affected primarily by PM and NOx emissions. The area near the Horseshoe Lake Facility is located along the North Canadian River in a farming and residential area. The closest airport is located approximately 12 miles north of the Facility in Luther, Oklahoma. Also, there are no Class I wilderness areas located within 100 km of the Facility. Therefore, there are no airports, scenic vistas, or other areas that could be affected by minor reductions in visibility.

CONCLUSIONS

The additional impact analyses consisting of a growth analysis, ambient air quality analysis, soils and vegetation impact analysis, and visibility impairment analysis is summarized below:

- Associated growth within the area of the Horseshoe Lake Facility as a result of the project will be zero;
- The ambient air quality within the area of the Facility will not be adversely affected by the project;
- The increased emissions associated with the project will not negatively affect the soils and vegetation within the area of the Horseshoe Lake Facility; and
- Visibility impairment is not anticipated due to a low net increase in NOx and PM emission rates.

SECTION VII. OKLAHOMA AIR POLLUTION CONTROL RULES

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

OAC 252:100-3 (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 252:100-4 (New Source Performance Standards) [Subpart GG Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on July 1, 2003, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. These requirements are addressed in the "Federal Regulations" section.

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

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
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 a HAP that the EPA may establish by rule
- 0.6 TPY of any one Category A toxic substance
- 1.2 TPY of any one Category B toxic substance
- 6.0 TPY of any one Category C toxic substance

Emissions limitations (lb/hr and TPY) have been incorporated from the previously-issued permits and the permit application.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Part 70/Title V sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.

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

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies maximum allowable emissions of particulate matter (PM). AP-42 (7/98), Table 1.4-2, lists the total PM emissions for natural gas fired boilers to be 7.6 lb/10^6 scf which is equivalent to 0.0076 lb/MMBTU. The fuel-burning equipment in this facility is rated from 3.4 to 3,960 MMBTU/hr. According to 252:100-19-4, the most stringent limit for fuel-burning equipment is 0.1 lb/MMBTU. Therefore, the natural gas fired boilers comply with this subchapter. AP-42 (9/98), Table 1.3-1 lists the PM emissions for fuel oil combustion (No. 2 oil fired) as 0.014 lb/MMBTU. The use of natural gas, No. 2 fuel oil, or used oil for fuel-burning equipment will be in compliance with Subchapter 19.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas, there is very little possibility of exceeding the opacity standards. When burning fuel oil and used oil, there may be visible emissions. The permit requires visible emission observations for the Unit 6 (2-B-01), Unit 7 (2-B-02), and the house heater boiler (2-B-04) when they are fired with fuel oil and whenever used oil is combusted in 2-B-04. When used oil is combusted in Unit 6 and 7, it only comprises no greater than 1.5% of the total heat input. The permit will require the use of natural gas or distillate fuel (fuel oil No. 2) for all fuel-burning equipment to ensure compliance with Subchapter 19.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 3 lists maximum ambient air concentration limits for existing equipment. It applies to electric generating Units 6, 7, and 8. A Screen3 model was used to determine compliance with OAC 252:100-31. Emission data was calculated based on the combustion of No 6 fuel oil in Units 6 & 7, simultaneously, with sulfur content of 2.0 weight percent to demonstrate the worst case secenario. The maximum concentrations are listed below:

Averaging Period	**Limits by OAC 252:100-31 (μg/m³)**	**Model Results (μg/m³)**
1 hr avg.	1300	1406
3 hr avg.	650	1265
24 hr avg.	130	562.4
annual avg.	80	112.48

The facility will adjust fuel oil flow rate as determined by the fuel oil sulfur analysis to maintain compliance with Part 3.

Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input. For liquid fuels the limit is 0.8 lb/MMBTU. Fuel-burning equipment at this facility uses No. 2 fuel oil, used oil and pipeline natural gas. Gas turbines 9&10 and auxiliary boilers were constructed after July 1, 1972, and therefore are subject to the limitations. For natural gas combustion, AP-42 (7/98), Chapter 1.4, Table 1.4-2 gives an emission factor of 0.6 pound of SO_2 per million cubic feet which equates to approximately 0.0006 lb/MMBTU which is in compliance with this subchapter. The permit will require the use of pipeline natural gas for the turbines and auxiliary boilers.
Part 5 also requires opacity and sulfur dioxide monitoring for new fuel-burning equipment rated above 250 MMBTUH. Equipment burning gaseous fuel is exempt from the opacity monitor requirement, so the turbines do not require such monitors. Equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitor requirement. The maximum permissible amount of sulfur in pipeline quality gas is more than an order of magnitude below 0.1 weight percent, so the turbines do not require such monitors.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.2 lb of NO_x per MMBTU. This applies to the gas turbines. The manufacturer of the turbines guaranteed a NO_x emission rate of 0.1 lb/MMBtu, which is in compliance with this subchapter.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Most of the storage tanks at the facility are exempt from this part since they were constructed prior to the new source applicability date and store materials with a low vapor pressure. Gasoline tank (6-B-11) is subject to this requirement.
Part 3 requires 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. The facility has gasoline loading but it is only used to fill vehicles with tanks less than 200 gallons.
Part 5 limits the VOC content of coatings used in coating lines or operations. Any painting operation will involve maintenance coatings of buildings and equipment and emit less than 100 pounds per day of VOCs and so is exempt.
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 effluent water separators which receive water containing more than 200 gallons per day of any VOC to be equipped vapor control devices. There is no water effluent separator at this location.
Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands that are properly installed and maintained in good working order and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. There is one gasoline pump associated with EUG 6-B-11. It is subject to this requirement.

OAC 252:100-41 (Hazardous Air Pollutants and Toxic Air Contaminants) [Applicable]
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2003, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, J, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, GGGG, HHHH, JJJJ, NNNN, OOOO, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, BBBBB, CCCCC, FFFFF, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, and SSSSS are hereby adopted by reference as they exist on July 1, 2003. These standards apply to both existing and new sources of HAPs. These requirements are covered in the “Federal Regulations” section.
Part 5 is a state-only requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category “A” pollutant above de minimis levels must perform a BACT analysis, and if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant which exceeds the de minimis level do not cause or contribute to a violation of the MAAC.

The de minimis levels for category A, B, and C are 0.57 lb and 0.6 TPY for category A substance, 1.1 lb/hr and 1.2 TPY for category B substance and 5.6 lb/hr and 6.0 TPY for category C substance. The HAPs and TACs which exceeds their de minimis level are formaldehyde and pentane. The SCREEN3 air dispersion model was used to estimate the ambient air concentration. The results are listed below:

HAPs	MAAC ($\mu g/m^3$)	Estimated Ambient Concentration ($\mu g/m^3$)
Formaldehyde	12	8.65
Pentane	35,000	153

The concentrations are within the maximum acceptable ambient concentration (MAAC) limits.

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 252:100-35	Carbon Monoxide	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Landfills	not in source category

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
Potential emissions for NO_X, CO, VOC, PM_{10} and SO_2 are greater than the level of significance of 100 TPY for this source category. PSD analyses are conducted in Section VI of this permit evaluation.

NSPS, 40 CFR Part 60 [Subpart GG is Applicable]
Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced after August 17, 1971. It regulates steam generating unit with more 250 MMBTU/hr heat input rate. The electric generating boilers at the facility were constructed before 1971 and therefore are exempt from the requirements of subpart D.

Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. It regulates electric generating units capable of combusting more than more 250 MMBTU/hr heat input of fossil fuel. The electric generating boilers at the facility were constructed before 1978 and therefore are exempt from the requirements of Subpart Da.

Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. It regulates steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 MMBTU/hr. The electric generating boilers at the facility were constructed before 1984 and therefore are exempt from the requirements of Subpart Db.

Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units regulates steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 100 MMBTU per hour or less, but greater than or equal to 10 MMBTU per hour. House heat boiler (2-B-04) is rated at 14.65 MMBTU/hr and was manufactured in 1971 and therefore is not subject to the applicable requirements of this Subpart.

Subpart K, Standards of Performance for Storage Vessels for Petroleum Liquid regulates petroleum liquids storage vessels constructed after June 11, 1973, and before May 19, 1978, with capacities above 40,000 gallons. Most tanks except one fuel tank (6-B-02) were either installed before the effective date of the regulation or their capacities are less than 40,000 gallons. Since the No. 2 through 6 fuel oil is not considered a petroleum liquid by this subpart, therefore, no tanks are subject.

Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction or Modification Commenced after May 18, 1978, and Prior to July 23, 1984. All tanks at this site are exempt from Subpart Ka since they were installed before the effective date of the regulation.

Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels). Kb regulates hydrocarbon tanks with capacities larger than 75 M^3 (19,813 gallons) and built after July 23, 1984. All tanks at this site are exempt from Subpart Kb since they were installed before the effective date of the regulation or their capacities are less than 19,813 gallons.

Subpart GG, Standards of Performance for Stationary Gas Turbines which commenced construction, reconstruction, or modification after October 3, 1977, and which have a heat input rating of 10 MMBTUH or more. Gas turbine of Unit 7 was constructed in 1963 and is not subject to this subpart. Gas turbines Unit 9 and 10 have a heat input rating of 550 MMBTU/hr and are subject to this subpart. The standard for nitrogen oxides shall be determined by the following equation:

$$STD = 0.0075 \times 14.4/Y + F$$

Where STD is allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis, Y is manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility, and F is NO_X emission allowance for fuel-bound nitrogen.

The heat rate of the turbines is 8,761 Btu/kwh or 9.2435 kjwh (from actual performance test). OG&E's natural gas analysis contained in the original construction application shows a nitrogen mole % content of 1.667%. This translates into a percent weight content of 2.88. Based on the table found in 40 CFR Part 60.332(a)(3) the F factor is 0.005. STD is calculated to be 167 ppm.

A NO_X emissions limitation of 50 lb/hr for each turbine is based on 25 ppmdv, therefore compliance will be maintained.

Subpart GG requires monitoring of fuel nitrogen and sulfur content. Nitrogen content monitoring is not required when pipeline-quality natural gas is the only fuel fired in the turbine. A quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly "stain tube" analysis is acceptable as sulfur content monitoring of the fuel under NSPS Subpart GG. Subpart GG also requires that a continuous monitoring system be installed and operated to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, coke oven emissions, mercury, radionuclides or vinyl chloride except for trace amounts of benzene. Subpart J affects process streams which 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 At This Time]
Subpart YYYY, Combustion Turbines. This subpart was proposed on January 14, 2003. As proposed, the subpart will affect only major sources of HAPs. Emission calculations have shown the facility to be a minor source of HAPs.
Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart was published in the Federal Register on June 15, 2004 and affects existing, new, and reconstructed spark ignition 4-stroke rich-burn (4SRB) RICE, new or reconstructed spark ignition 2-stroke lean-burn (2SLB) RICE, new or reconstructed 4-stroke lean-burn (4SLB) RICE, and new or reconstructed compression ignition (CI) RICE, with a site-rating greater than 500 brake horsepower, that are located at a major source of HAP emissions. This facility is not a major source of HAPs
Subpart DDDDD, "Industrial-Commercial-Institutional Boilers and Process Heaters" was signed by EPA on February 26, 2004, and affects new and existing boilers and process heaters located at major sources of HAPs. This facility is a minor source of HAPs.

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

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

None of the emission units use a control device to achieve compliance with an applicable emission limit except Units 9 and 10. Since electric generating Units 9 and 10 are acid rain program affected units, there are standards applied to them and they are not subject to CAM.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
The definition of a stationary source does not apply to transportation, including storage incident to transportation, of any regulated substance or any other extremely hazardous substance under the provisions of this part. The definition of a stationary source also does not include naturally occurring hydrocarbon reservoirs. Naturally occurring hydrocarbon mixtures, prior to entry into a natural gas processing plant or a petroleum refining process unit, including: condensate, crude oil, field gas, and produced water, are exempt for the purpose of determining whether more than a threshold quantity of a regulated substance is present at the stationary source.

Acid Rain Program, 40 CFR Part 72 (Permit Requirements) [Applicable]
Acid Rain Permit No. 97-137-AR was issued on December 2, 1997, and remains effective.

Acid Rain Program, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
SO_2 initial allowances as published in 40 CFR 73.10 are listed in Acid Rain Permit No. 97-137-AR. However, all allowances can be traded, bought, and sold. Therefore, the actual allowances held by an affected unit may change which will not necessitate a revision to the permit.

Acid Rain program, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
Certification testing has been completed for the CEM systems required for units 6, 7 and 8, and the EPA has issued approval of certification on September 22, 1997 for these units. The facility has completed certification testing for units 9 and 10 and submitted application to EPA for approval on March 8, 2001.

Acid Rain Program, 40 CFR Part 76 (NO_X Emission Reduction Program) [Not Applicable]
40 CFR Part 76 establishes NO_X emission limitations for coal-fired electric utility units. The boilers at the facility are not coal-fired and therefore are exempt from the requirements of this Part.

Stratospheric Ozone Protection, 40 CFR Part 82 [Applicable]
This facility does not produce, consume, recycle, import, or export any controlled substances or controlled products as defined in this part, nor does this facility perform service on motor (fleet) vehicles which involves ozone-depleting substances. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

SECTION IX. COMPLIANCE

Tier Classification And Public Review

This application has been determined to be a Tier **II** based on the request for a significant modification to a Part 70 Permit. The applicant has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the real property.

The applicant published the "Notice of Filing a Tier II Application" in the *Eastern Oklahoma County News* on May 27, 2004, a weekly newspaper of general circulation in Oklahoma County. The notice said that the application was available for public review at the Harrah Public Library, 1930 N. Church, Harrah, Oklahoma 73045 or at the AQD office. The applicant also published the "Notice of Tier II Draft Permit" in the *Eastern Oklahoma County News* on September 1, 2004. The notice stated that the permit draft was available for public review for 30 days at the Harrah Public Library, or at the Air Quality Division's main office. This facility is not located within 50 miles of the border with a contiguous state. Information on all permits is available for review by the public in the Air Quality Section of DEQ Web Page: *http://www.deq.state.ok.us*. No comments were received from the public. The proposed permit was sent to EPA Region VI for a 45-day review period. No comments were received from the EPA.

Fee Paid

The fee assessed for this construction permit modification is $1,500 and $2,000 has been received, thus, the overpayment of $500 will be refunded.

SECTION X. SUMMARY

The source has demonstrated the ability to achieve compliance with the requirements of all applicable air pollution control rules and regulations. Ambient air quality standards are not threatened at the site. There are no active Compliance or Enforcement Air Quality issues at this facility. Approval of construction permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Oklahoma Gas & Electric Company **Permit Number 97-137-C (M-3) (PSD)**
Horseshoe Lake Generation Station

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on July 17, 2003. The Evaluation Memorandum dated November 22, 2004, 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 operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

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

EUG 1. Electric Generating Boilers and Turbine

EU ID#	Make	Heat Capacity (MMBTUH)	Serial #	Installed Date
2-B-01, Unit 6	Babcock & Wilcox	1,740	RB-260	1958
2-B-02, Unit 7	Babcock & Wilcox Boiler	2,379	RB-381	1963
2-B-02, Unit 7	GE Gas Turbine	511	127744	1963
2-B-03, Unit 8	Combustion Engineering	3,960	20754	1968

EUG 2. House Heat Boiler

EU ID#	Make/Model	Heat Capacity (MMBTUH)	Serial #	Manufactured Date
2-B-04	Cleaver Brooks/CB657-350	14.65	L-53234	1971

The boilers and turbine listed above are “grandfathered” and are limited to the existing equipment as they are.

EUG 3. Electric Generating Gas Turbines

EU ID#	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
3-B-01, Unit 9	GE/LM6000 PC Sprint	550	308771	2000
3-B-02, Unit 10	GE/LM6000 PC Sprint	550	265046	2000

EUG 4. Auxiliary Boilers

EU ID#	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
4-B-01	Precision Boiler/ FPH62-100-P4200N	3.4	B000020B	2000
4-B-02	Precision Boiler/ FPH62-100-P4200N	3.4	B000020	2000

EUG 5. Emergency Diesel Generator

EU ID#	Make/Model	hp	Serial #	Installed Date
5-B	General Motor/MP36A	2,875	63399	1966

EUG 6. Storage Tanks

Point and EU ID#	Capacity (gallon)	Material Stored	Installed Date
6-B-01	2,310,000	Fuel Oil	1958
6-B-02	2,310,000	Fuel Oil	1974
6-B-03	230,000	Used Oil	1962
6-B-10	500	Diesel Fuel	1985
6-B-11	1,058	Gasoline	1992
6-B-12	1,058	Diesel Fuel	1992
6-B-13	300	Diesel Fuel	1992
6-B-14	2,730	Diesel Fuel	1963
6-B-15	420	Kerosene	1992

Emission Limits for House Heat Boiler (EUG 2), Electric Generating Gas Turbines (EUG 3) and Auxiliary Boilers (EUG 4)

EU ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2-B-04	2.09	3.14	1.19	1.79	0.08	0.12	7.42	11.13	0.21	0.31
4-B-01	0.34	0.17	0.29	0.14	0.019	0.01	0.002	0.001	0.026	0.013
4-B-02	0.34	0.17	0.29	0.14	0.019	0.01	0.002	0.001	0.026	0.013

Emission Limits for Unit 8 (EUG 1) and Electric Generating Gas Turbines (EUG 3)

EU ID#	*NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2-B-03	--	--	--	--	--	--	--	--	--	--
3-B-01, Unit 9	50.0	--	77.0	--	5.5	--	5.5	--	3.85	--
3-B-02, Unit 10	50.0	--	77.0	--	5.5	--	5.5	--	3.85	--
Total		**1032.86**		**292.52**		**29.24**		**2.45**		**28.67**

* The combined total NO_X emissions from 2-B-03, 3-B-01, and 3-B-02 shall be limited to 1032.86 tons per year. The NO_X emissions from the Turbines (Unit 9 and 10) shall be no greater than 167 ppmdv at 15% O_2 for each turbine. NOx and SO_2 emission limits on a lb/hr basis are 3-hour averages. CO and VOC emission limits on a lb/hr basis are 8-hour averages. PM_{10} emission limits on a lb/hr basis are 24-hour averages.

Emissions from the storage tanks are considered insignificant based on existing equipment items and do not have a specific limitation.

2. NO_X emissions from Unit 9 (3-B-01) and Unit 10 (3-B-02) shall be determined from CEM data. NO_X emissions from emission unit 2-B-04 shall be determined by calculations using most recent AP-42 emissions factors and gas meter measurements. NO_X emissions from emission unit 4-B-01 and 4-B-02 shall be determined by calculations using accepted emissions factors and hour meter measurements. Compliance with the NO_X emission limits in tons per year in Specific Condition No. 1 shall be determined by the sum of the emissions from Unit 8 and the gas turbines (Units 9 and 10) Tons per year emissions shall be determined monthly with compliance based on a calendar year. [OAC 252:100-8-6(a)]

3. Each turbine and boiler at the facility shall have a permanent identification plate attached. [OAC 252:100-8-6(a)]

4. The electric generating boilers Unit 6 and 7 shall use natural gas as their primary fuel and #2 fuel oil as secondary fuel. The boiler Unit 8, gas turbines and auxiliary boilers shall be authorized to utilize pipeline natural gas. The house heat boiler shall be authorized to utilize natural gas, used oil, or No. 2 fuel oil. The sulfur content of fuel oil shall be no greater than 0.5 weight percent for No. 2 fuel oil. [OAC 252:100-31]

5. The permittee shall be allowed to incinerate company-generated non-hazardous materials. The permittee shall also be allowed to incinerate used oil that is company employee generated or company retiree generated. These materials shall not be classified RCRA “hazardous waste” according to 40 CFR 261 except as allowed by 40 CFR 266.108. Materials allowed to be incinerated may include, but are not limited, used oil, used solvent, corrosion inhibitors, on-line cleaning solution, and antifreeze. The Unit 6 and 7 boilers may incinerate corrosion inhibitors used in Units 9 and 10. Annual waste incinerated and the maximum incineration rate shall be such that emissions do not exceed de minimis levels set forth in OAC 252:100-41.

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

6. Combustion turbines (Unit 9 and Unit 10) shall be operated with water injection for NO_x control sufficient to meet the limits of Specific Condition No. 1. [OAC 252:100-8-6(a)]

7. The turbines (Units 9 and 10) are subject to 40 CFR Part 60 Subpart GG and shall comply with all applicable requirements. [40 CFR Part 60 40 CFR §60.330 to §60.335]

a. Each turbine shall comply with the standard for nitrogen oxides of §60.332(a)(1).
b. Each turbine shall either comply with the sulfur dioxide emission limitation of 0.015% by dry volume at 15% O_2 or the fuel sulfur content limitation of 0.8% by weight. [§60.333]
c. Monitoring of the sulfur and nitrogen content of the fuel being fired in the turbine is required pursuant to §60.334(b). The AQD has determined that the following custom schedule and testing is appropriate for this section. A quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly “stain tube” analysis is acceptable as sulfur content monitoring of the fuel under NSPS Subpart GG. If after four quarters, the sulfur content is shown to be consistent, the sulfur content monitoring can be conducted annually. Monitoring of fuel nitrogen content shall not be required while pipeline quality natural gas is the only fuel fired in the gas turbines.
d. Excess emissions shall be reported pursuant to §60.334(c).
e. Like-kind replacement of turbines within temporary periods of approximately 6 months or less for maintenance purposes are authorized. The permittee shall notify AQD in writing in advance of the start-up of the replacement turbine(s). Said notice shall identify the equipment removed and shall include the new turbine make, model, and horsepower; date of the change, and any change in emissions.
f. The permittee shall comply with the test methods and procedures of §60.335 except as stated above.

8. The electric generating boilers (Unit 6, 7 and 8) and gas turbines (Unit 9 and 10) are subject to the Acid Rain Program and shall comply with all applicable requirements including the following:

[40 CFR Part 72, 73, and 75]

a. SO_2 allowances
b. Monitoring as required by 40 CFR Part 75
c. Report quarterly emissions to EPA
d. Conduct RATA tests
e. QA/QC plan for maintenance of the CEMS

9. If Continuous Opacity Monitoring is not utilized, the permittee shall conduct daily visual observations of the opacity from the boiler exhausts while burning fuel oil (Units 6, 7 and 2-B-04) or used oil (2-B-04) for more than 24 continuous hours and keep a record of these observations. If visible emissions are detected, then the permittee shall conduct a single opacity reading in accordance with EPA Reference Method No. 9 (EPA Method 9). If the EPA Method 9 indicates an opacity greater than 20%, hourly EPA Method 9's will be conducted until compliance is determined. Once compliance is determined, the facility will revert back to daily visual observations as required by this paragraph. [OAC 252:100-25]

10. The following records shall be maintained on-site or at a local field office to verify insignificant activities. [OAC 252:100-43]

a. For stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generation or for peaking power service: operating hours per year.
b. For fuel storage/dispensing equipment solely for facility owned vehicles: Purchase Records (gallons/day averaged over a 30-day period).
c. For storage tanks containing volatile organic liquids with vapor pressures less than 1.0 psia and having capacities less than 10,000 gallons: capacity of the tanks, and contents.
d. For activities that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: type of activity and the amount of emissions from that activity (cumulative annual).

11. When monitoring shows NO_x concentrations in excess of the ppm or lb/hr limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions during start-up, shut-down, and malfunction of air pollution control equipment. Requirements include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions. [OAC 252:100-9]

12. The permittee shall keep operation and maintenance (O&M) records for these "grandfathered" emission units (Unit 6, 7, 8 and 5-B). Such records shall at a minimum include the hours of operation, maintenance and type of work performed. [OAC 252:100-8-6 (a)(3)(B)]

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

a. Operation and maintenance records for grandfathered emission units (Unit 6, 7, 8 and 5-B).
b. Operating hours for turbines (Units 9 and 10) and each auxiliary boiler, fuel consumption for house heat boiler (monthly and summed over a calendar year) as required to determine the tons per year limitation; NO_X emissions in lb/hr and tons per year.
c. Total fuel consumption for turbines (Units 9 and 10) (monthly and calendar 12 month totals).
d. Sulfur content of natural gas (quarterly or annual supplier statements or quarterly or annual “stain-tube” analysis), sulfur content of fuel oil (as per 40 CFR Part 75 Appendix D).
e. Monitoring data of water-fuel ratio (during periods of NO_X CEMS downtime) and fuel usage (continuous).
f. The amount of corrosion inhibitors incinerated in Units 9 and 10 (gallons/year).
g. Emission data as required by the Acid Rain Program.
h. RATA test results from periodic CEMS certification tests.
i. Visible emissions observations taken in accordance with Specific Condition 9 while burning fuel oil (Units 6, 7 and 2-B-04) or used oil (2-B-04).

14. The permitee shall have the discretion of determining which records will be maintained in computerized form.

15. No later than 30 days after each anniversary date of the issuance of the original Title V permit, 97-137-TV, 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. The following specific information is required to be included:

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

a. Summary of monitoring, operation and maintenance records required by this permit.
b. Summary of NO_X emissions.
c. Executive summary of quarterly RATA reports.

16. This permit supercedes Permit No. 97-137-C (M-2), which is now null and void.