OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **March 21, 2007**

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FROM: Herb Neumann, DEQ Regional Office at Tulsa (ROAT)

SUBJECT: Evaluation of Permit Application No. **2003-360-C (M-1)(PSD)**
Public Service Company of Oklahoma (PSO)
Two Combustion Turbines at Riverside Power Station
Section 32, T18N, R13E, Tulsa County (35.996° N, 95.959° W)
Located at 116th Street and Arkansas River
Directions from the intersection of US 75 and 111th St: two miles east to Peoria, then 1/2 mile south to 116th St, then approximately one mile east.

I. INTRODUCTION

The Riverside Power Station ("the facility") is owned and operated by PSO under Permit No. 2003-360-TVR, issued February 3, 2005. PSO, a unit of American Electric Power (AEP), proposes to construct and operate two natural gas-fired peaking electric generating units at the facility.

The added power block will consist of two General Electric Frame 7EA simple cycle combustion turbine generators (CTGs). Each of the turbines will have a nominal peak heat input of approximately 1,078 million British thermal units per hour (MMBTUH) and an average heat input of approximately 930 MMBTUH. The combustion turbines will fire only pipeline-quality natural gas and are equipped with General Electric's 9/42 Dry Low-NO_x (DLN) combustor technology. The proposed new units will each have a nominal electrical generating capacity of 89 MW.

This is a fossil fuel generating facility with rated heat input greater than 250 MMBTUH and is one of those categories subject to PSD consideration at the 100 TPY level of emissions. Project emissions will exceed the PSD Significant Emission Rate (SER) for NO_x, CO and PM_{10}. Therefore, the project is subject to Prevention of Significant Deterioration (PSD) review. The

PSD regulations require Best Available Control Technology (BACT) and air quality analyses for each pollutant for which the project is significant.

II. FACILITY DESCRIPTION

The existing facility has two operating units that generate electricity using steam turbines (SIC 4911). The boilers providing steam to all generating units are primarily gas-fueled, with #2 fuel oil as a secondary fuel. There are two operating scenarios for the existing facility. In Scenario I, pipeline-grade natural gas is the primary fuel. In Scenario II, #2 fuel oil is used. The facility may operate with combinations of these fuels, but this mode is not identified as a separate Scenario because emissions will not exceed those possible under Scenario II. Information available for review in the application for the renewal Title V permit indicated that Units 1 and 2 operated exclusively under Scenario I in 2003, for annual capacity factors of 23% and 25%, respectively. The auxiliary boiler uses only natural gas, is not used in conjunction with a fully loaded unit, and had a 12-month-rolling capacity factor of 7.8% through September 2006.

III. EQUIPMENT

The two new gas turbines will be GE7EA combustion turbines manufactured before 2003, each with nominal output of 89 MWe. Heat input is expected to average 1,078 MMBTUH. The turbines will use dry low-NO_x (DLN) combustors. A typical DLN burner for a turbine consists of one diffusion flame pilot nozzle surrounded by several equally spaced premix flame main nozzles. The formation of NO_x is influenced by how much gas is burned in the pilot flame and how much is burned in the surrounding combustor nozzles. The multi-nozzle design spreads the combustion volume into a wider, cooler, less concentrated flame. Typically, for natural gas fuel, approximately 7 to 10 vol% of the total gas flow is sent through the pilot nozzle. The new emission units will be identified as CT-4 and CT-5 and will reside in EUG 5.

Existing equipment consists of the following. Stack data are found in the renewal permit memo.

EUG 1 Grandfathered Boilers

Point	Make/Model	MW-Gross	MMBTUH	Const Date
1	Babcock & Wilcox supercritical pressure-fired steam generator UP-99	490	4684	3/71
2	Babcock & Wilcox supercritical pressure-fired steam generator UP-113	490	4766	3/71

EUG 2 ChemStore

Material	Stored Quantity	Use
Hydrogen	564 MCF (3 lbs)	Generator cooling
Ammonia	8,500 lb	Control of boiler water pH
Hydrazine	Three 30-gal drums @ 35% (300 lbs)	Closed cooling systems & aux boiler

EUG 3 PlantWide

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

EUG 4 Auxboiler

The auxiliary boiler is given a new point ID congruent with new IDs assigned to the proposed turbines.

Point	Make/Model	MMBTUH	Const Date
5	Babcock & Wilcox packaged boiler	226	2/93

EUG 5 Combustion Turbines

Point	EU Name, Model	MW Gross	MMBTUH	Serial No.	Const Date
3	GE7EA Combustion Turbine	89	1,078	TBD	2007
4	GE7EA Combustion Turbine	89	1,078	TBD	2007

Insignificant Sources

These include a diesel-fired 3,600-hp emergency generator, three 11,256,000-gallon fuel oil tanks, one 9,135,000-gallon fuel oil tank, one 35,200-gallon diesel storage tank, one 8,400-gallon natural gas condensate tank, and two 16,200-gallon lube oil tanks. Williams Pipe Line supplies fuel to the large tanks as necessary, although the tanks are currently empty and have been for years. The condensate tank in the gas yard is the property of the gas supplier, but is listed here for the sake of completeness. Metering facilities and condensate tanks in such gas yards are the property of the pipeline company and none has exceeded the insignificant criterion of 10,000 gallons capacity. Other insignificant activities include cold degreasing operations, welding and soldering operations, torch cutting and welding, drum staging areas, maintenance surface coating and degreasing operations, exhaust systems for chemical, paint and solvent storage rooms, and hand wiping and spraying of solvents. The current project will not add new insignificant activities to the facility.

IV. EMISSIONS

The following table shows emissions calculated in the memorandum associated with the existing operating permit, rounded to three significant digits. Assumptions and calculations are not repeated here. Note that the worst-case is shown for each pollutant. In the case of Hazardous Air Pollutants (HAP), that number occurs when evaluating natural gas, where the principle constituent of HAP is hexane, at 72.8 TPY. The principle constituent when evaluating oil is formaldehyde, at 14.8 TPY. A separate calculation was performed for hydrogen chloride. Factors for some constituents have been questioned and these amounts may be altered in future actions. Addition of the new equipment is not expected to alter the use of the existing equipment or to increase emissions from the equipment.

Table 1

Pollutant	TPY
PM_{10}	532
SO_2	18,900
NO_X	11,500
CO	3,440
VOC	226
HAP	76.5
Hydrogen chloride	54.2

Some of the turbines' emissions are estimated based on GE vendor-supplied emissions data. GE supplied data for three base temperature conditions, with representative values for each shown in Table 2. Worst-case emission factors resulting from these input conditions were then used to evaluate emissions. The SO_2 factor derives from gas contract conditions of 5 gr/100 scf maximum and 0.25 gr/100 scf average for sulfur. The lead factor is taken from Table 1.4-2 of AP-42 (7/98). Finally, the factor for sulfuric acid mist assumes that 10% of SO_2 is converted to SO_3, all of which is converted to H_2SO_4. The manufacturer's emission for filterable PM was doubled to account for condensables. All factors are shown in Table 3.

Table 2 - Base conditions

Property	Value		
Ambient temperature	6°F	72°F	103°F
Evaporative cooler	Off	On	On
Output (megawatts)	95.6	79.4	71.4
Exhaust flow (scfm)	568,000	500,000	469,000
Temperature (°F)	960	1,004	1,024

Table 3 - Emission factors (each unit)

Pollutant	Factor
PM_{10}	10 lbs/hr
SO_2	5 max or 0.25 average gr S/100 scf
NO_X	9 ppmvd @ 15% O_2
CO	25 ppmvd @ 15% O_2
VOC	1.4 ppmvw
Lead	0.0005 lbs/MMscf
H_2SO_4	0.115 lbs/hr

Due to their operation as peaking units, these turbines can be expected to experience a regular cycle of start-up and shutdown events during which NO_x and CO emission rates are higher than at normal base load levels. These elevated levels of emissions are accounted for in the pollutant estimates described below. The facility estimates that these units will not be used significantly during at least three months of each year, so they start the process of estimating peaking emissions by assuming that the 2,000 hours of operation they have requested will occur over a 39-week period. Further, they estimate that there will be one cold start for every three warm starts, and that there will be roughly four cycles of start-up and shutdown in a typical operating week. “Warm” starts are those that occur within 24 hours of the unit’s most recent shutdown. All other starts are “cold.” All of these assumptions are made with a view toward maximizing their estimated emissions. Each cycle is estimated to consist of a 2-hour start-up, a 9.82-hour “normal” run, and a 1-hour shutdown. Emissions during the shutdown period and during both cold and warm starts are based on actual CEMS data gathered from similar GE turbine units. All of the CEMS-derived information is shown in units of pounds per hour. The following table assembles all of these assumptions and shows the resulting calculations. The last row of the table averages data for one cold start and three warm start cycles together to obtain a conservatively high value that can be used in estimating long term emissions.

Table 4

	Hours of Operation	**NO_x**		**CO**	
		lb/hr	**lb/event**	**lb/hr**	**lb/event**
Cold Start	2	186.06	372	313.64	627
Normal	9.82	35.00	344	59.00	579
Shutdown	1	20.29	20.3	34.20	34.2
Each cold cycle		**57.4**	**736**	**96.8**	**1,241**
Warm Start	2	56.81	114	95.77	192
Normal	9.82	35.00	344	59.00	579
Shutdown	1	20.29	20.3	34.20	34.2
Each warm cycle		**37.1**	**478**	**62.8**	**805**
Average over 1 cold and 3 warm cycles		**42.2**		**71.3**	

Table 3 showed emission factors for all pollutants, except that those listed for NO_X and CO were restricted for use only during “normal” operation. Table 4 showed NOx and CO factors that can be used to estimate long-term emissions. Combining information from these tables with the facility’s request to establish a 2,000-hour/year limit of operations for each unit gives rise to the following Table 5. The hourly rates are based on Table 3 values. Annual rates are calculated using values from Table 4 for NO_X and CO, with all others taken from Table 3, and inflating to 2,000 hours for each unit.

Table 5 - Estimated Emissions from Combustion Turbines

Pollutant	**lb/hr each**	**TPY each**	**TPY combined**
NO_x	35.0	42.2	84.4
CO	59.0	71.3	143
SO_2	0.75*	0.75	1.50
PM_{10}	10.0	10.0	20.0
VOC	2.0	2.0	4.0
Pb	0.0005	0.0005	0.001
H_2SO_4	0.115	0.12	0.24

*This is the average value. A one-hour maximum could be as high as 15.

The facility proposes that the limit on 2,000 hours of operation be monitored by fuel consumption as a surrogate measure. Further, in order to allow for flexibility in operations, the facility wishes to have a combined limit, so that either unit could be utilized as needed to satisfy customer demand. This is proposed because one unit may not operate at full capacity or may be unavailable due to malfunction or maintenance issues. Based on 1,078 MMBTUH for each unit, 2,000 hours of operation for each, and historic heat value of approximately 1,020 BTU/CF, the proposed limit equates to 4,228 MMSCF per year.

Speciated HAP emission factors for combustion turbines are found in Tables 3.1-3 of AP-42 (4/00). The formaldehyde emission factor in that table is rated as an E, which is the lowest reliability. A newer and more reliable value has been taken from EPA memorandum *HAP Emissions Control Technology for New Stationary Combustion Turbines*, dated August 21, 2001, by Sims Roy. The value used in that memo is based on the 95th percentile high range for eight tested turbines with ratings between 10 and 170 mW.

Table 6 - HAP Emissions for Combustion Turbines

HAP	Factor (lb/MMBtu)	Lb/hr each	TPY each	TPY total
Acetaldehyde	4.00E-05	0.043	0.043	0.086
Acrolein	6.40E-06	0.007	0.007	0.014
Benzene	1.20E-05	0.013	0.013	0.026
1,3 Butadiene	4.30E-07	5E-04	5E-04	0.001
Ethylbenzene	3.20E-05	0.037	0.037	0.074
Formaldehyde	2.02E-04	0.233	0.233	0.466
Naphthalene	1.30E-06	1.5E-03	1.5E-03	0.003
PAHs	2.20E-06	0.003	0.003	0.006
Propylene Oxide	2.90E-05	0.033	0.033	0.067
Toluene	1.30E-04	0.150	0.150	0.300
Xylenes	6.40E-05	0.074	0.074	0.148
Totals		**0.560**	**0.560**	**1.12**

V. PSD REVIEW

Table 7 shows the annual emission totals from Table 5 and compares them with PSD significance thresholds to determine whether any exceed the amount for which review is required.

Table 7 - PSD Comparison (TPY)

Pollutant	NO_X	CO	VOC	SO_2	PM_{10}	Lead	H_2SO_4
Emissions	**84**	**143**	**4**	**1.5**	**20**	**0.001**	**0.24**
Threshold	**40**	**100**	**40**	**40**	**15**	**0.6**	**7**
Significant?	**Y**	**Y**	**N**	**N**	**Y**	**N**	**N**

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

A. Determination of best available control technology (BACT).
B. Evaluation of existing air quality.

C. Evaluation of PSD increment consumption.
D. Analysis of compliance with National Ambient Air Quality Standards (NAAQS).
E. Pre- and post-construction ambient monitoring.
F. Evaluation of source-related impacts on growth, soils, vegetation, visibility.
G. Evaluation of Class I area impacts.

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

The pollutants subject to review under the PSD regulations, and for which a BACT analysis is required, include nitrogen oxides (NOx), carbon monoxide (CO), and particulates less than or equal to 10 microns in diameter (PM_{10}). The BACT review follows the "top-down" approach recommended by the EPA, as shown by the following steps. The facility has compressed the process, by eliminating some technologies before moving to the next step. For instance, NO_X control technology SCR is eliminated during the Step 1 discussion by noting that its excessive cost will eventually disqualify it from BACT, regardless of the intervening steps.

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

The only emission units for which a BACT analysis is required are the combustion turbines since these are the only sources in the project. Economic as well as energy and environmental impacts are considered in a BACT analysis. The EPA-required top down BACT approach must look not only at the most stringent emission control technology previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc. PSO identified these technologies and emissions data through a review of 45 determinations found in EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as EPA's NSR and CTC websites, recent DEQ BACT determinations for similar facilities, and vendor-supplied information.

Table 8 following lists control technologies that were identified for controlling emissions from gas turbines and their effective emission reduction levels.

Table 8 – Control Technologies

Pollutant	Technology	Potential Control Efficiency (%)
NOx	Catalytic Combustion (XONON™)	~95
	Selective Catalytic Reduction (SCR)	50 to 95
	Dry Low NOx Combustors (DLN)	40 to 60
	Selective Non-Catalytic Reduction (SNCR)	40 to 60
	Water / Steam Injection	30 to 50
	Good Combustion Practices	Base Case
CO	Catalytic Oxidation	60 to 80
	Good Combustion Practices	Base Case
PM / PM_{10}	Good Combustion Practices	10 to 30
	Clean Burning Fuels	Base Case

NOx BACT Review

Nitrogen oxides (NO_X) are formed during the fuel combustion process. There are three types of NO_X formations; thermal NO_X, fuel-bound NO_X, and prompt NO_X. Thermal NO_X is created by the high temperature reaction in the combustion chamber between atmospheric nitrogen and oxygen. The amount that is formed is a function of time, turbulence, temperature, and fuel-to-air ratios within the combustion flame zone. Fuel-bound NO_X is created by the gas-phase oxidation of the elemental nitrogen contained within the fuel. Its formation is a function of the fuel nitrogen content and the amount of oxygen in the combustion chamber. Fuel NO_X is temperature-dependent to a lesser degree; at lower temperatures, the fuel-bound nitrogen will form N_2 rather than NO_X. The fuel specification for these turbines, natural gas, has inherently low elemental nitrogen, so the effects of fuel NO_X are insignificant in comparison to thermal NO_X. Prompt NO_X occurs primarily in combustion sources that use fuel rich combustion techniques. The formation of prompt NO_X occurs through several early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. The reactions primarily take place within fuel rich flame zones and are usually negligible when compared to the formation of NO_X by the thermal NO_X process. Combustion turbines (CTs) generally have high mixing efficiencies with excess air, rich combustion zones rarely exist, and the formation of prompt NO_X is not deemed a significant contributing factor towards NO_X formation.

The applicant has proposed dry low NO_X burners (DLN) to achieve 9 ppmvd NO_X or less, adjusted to 15% oxygen as BACT.

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

Catalytic Combustion (XONON™) XONON™ is a catalytic combustion system developed by Catalytica Energy Systems, Incorporated (CESI). In a typical combustor, the fuel/air mixture burns at flame temperatures that may approach 2,700 ^{o}F. With the XONON system, the fuel/air mixture is oxidized across several small catalyst beds allowing ignition of the mixture at less than the optimal NO_x-forming flame temperature.

CESI claims that XONON™ can achieve NO_x emission levels of two parts per million without additional controls. A 1.5 MW Kawasaki turbine commenced commercial operation using XONON in October 1998 in Santa Clara, California. CESI also is working with General Electric to develop XONON™ technology for the larger Frame 7 machines to be installed at the proposed 750 MW natural gas-fired Pastoria Energy Facility, near Bakersfield, California. However, General Electric does not currently offer XONON™ as an option on these machines, and there is not yet sufficient operating experience on other large gas turbines to ensure reliable performance. Thus, the XONON™ catalytic combustion system is not considered further.

Selective catalytic reduction (SCR) is a post-combustion gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. Ammonia and nitric oxide (NO) react on the catalyst surface to form diatomic nitrogen and water. The overall chemical reaction can be expressed as:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$

Removal efficiencies between 50 and 95 percent can be achieved through this reaction when exhaust temperatures are maintained within the optimum temperature range of 575° F to 750° F. Combined cycle turbines that operate with HRSGs (heat recovery steam generators) and duct burners are generally able to meet this optimum exhaust temperature without difficulty due to the heat exchange conducted within the post-CT equipment. Simple cycle turbines (such as the proposed units being installed by PSO) operate with much higher exhaust temperatures (900° F is common) due to the lack of post-combustion turbine heat recovery equipment. This higher exhaust temperature reduces SCR effectiveness by reducing catalyst lifetime and increasing contamination potential. While it would be appropriate to adjust SCR removal efficiencies for simple cycle turbines, BACT evaluations have still been conducted assuming 50-95% efficiency.

SCR units have the ability to function effectively under fluctuating temperature conditions (usually ± 50° F), although fluctuation in exhaust gas temperature reduces removal efficiency slightly by disturbing the NH_3/NO_X molar ratio. Below the optimum temperature range, the catalyst activity is reduced, allowing unreacted NH_3 to slip through. Above the optimum temperature range NH_3 is oxidized, forming additional NO_x, and the catalyst may suffer thermal stress damage. In addition, the use of NH_3 in SCR technology poses additional environmental and health risks due to the potential for NH_3 slip or accidental release.

Although SCR has the potential for successful NO_x reduction, the cost for SCR is estimated at $65,849 per ton of NO_x removed. This cost level is considered to be economically infeasible for BACT. Due to high cost, SCR is not selected as BACT for control of NO_x emissions.

<u>Dry Low NOx Combustor (DLN)</u> technology premixes air and fuel in a lean mixture to significantly reduce peak flame temperature and thermal NO_x formation. Conventional combustors are diffusion controlled where fuel and air are injected separately. Combustion occurs locally at stoichiometric interfaces resulting in hot spots that produce high levels of NO_x. In contrast, DLN combustors generally operate in a premixed mode where air and fuel are mixed before entering the combustor. The underlying principle is to supply the combustion zone with a completely homogeneous, lean mixture of fuel and air. DLN combustor technology generally consists of hybrid combustion, combining diffusion flame (for low loads) plus DLN flame combustor technology (for high loads). Due to the flame instability limitations of the DLN combustor below approximately 50 percent of rated load, the turbine is typically operated in a conventional diffusion flame mode until the load reaches approximately 50 percent. As a result, NO_x concentration levels rise when operating under low load conditions. For a given turbine, the DLN combustor volume is typically twice that of a conventional combustor.

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

PSO has selected DLN combustion as BACT and proposes a NO_x BACT limit of 9 ppmvd at 15% O_2 for the turbines. Although the RBLC search mentioned earlier (presented in Appendix C of the application) shows that multiple combustion turbines have installed SCR as BACT, there are no records in the RBLC of peaking units utilizing control technology more stringent than DLN combustors as BACT. Although there are entries in the RBLC of simple cycle turbines constructed with SCR, these entries are either driven by LAER (which cannot be used to establish BACT) or are a case-by-case determination.

Water or Steam Injection is a control technology that utilizes water or steam for flame quenching to reduce peak flame temperatures and thereby reduce NO_X formation. The injection of steam or water into a gas turbine can also increase the power output by increasing the mass throughput; however, it also reduces the efficiency of the turbine. Typically, where applied to combustion turbines with diffusion combustors, water injection can achieve emission levels of 25 ppm while firing natural gas. This control technology is less effective than the proposed technology and will not be discussed further.

Selective Non-Catalytic Reduction (SNCR); Thermal $DeNO_X$™ SNCR is based on the principle that ammonia or urea reacts with NO_X in the flue gas to form N_2 and H_2O. In practice, the technology has been applied in boilers by injecting ammonia into the high temperature (e.g., 1,300 ºF to 2,000 ºF) region of the exhaust stream. Incorrect location of injection points, insufficient residence times and miscalibration of injection rates may result in excess emissions of ammonia (ammonia slip), a toxic air pollutant. When successfully applied SNCR has shown reduction in NO_x emissions from boilers of 35 to 60 percent.

Thermal $DeNO_X$ is a high temperature selective non-catalytic reduction (SNCR) of NO_X using ammonia as the reducing agent. Thermal $DeNO_X$ requires the exhaust temperature to be above 1,800 ºF.

Dry low NOx burners (DLN) that achieve 9 ppmvd NOx or less, adjusted to 15% oxygen are acceptable as BACT.

CO BACT Review

Carbon monoxide is formed as a result of incomplete combustion of fuel. 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 also tend to result in high NO_X emissions. Conversely, a low NO_X emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO emissions. Thus a compromise is established whereby the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while also optimizing CO emission rates.

The rate of formation of CO during natural gas combustion depends primarily on the efficiency of combustion. Formation of CO occurs in small, localized areas around the burner where oxygen levels cannot support the complete oxidation of carbon to CO_2. Efficient burners can minimize the formation of CO by providing excess oxygen or by thoroughly mixing the fuel with air.

Catalytic Oxidation can reduce CO emissions resulting from natural gas combustion. The oxidation is carried out by the following overall reaction:

$2CO + O_2 \rightarrow 2CO_2$

This reaction is promoted by several noble metal-enriched catalysts at high temperatures. Under ideal operating conditions, this technology can achieve an 80% reduction in CO emissions. Prior to entering the catalyst bed where the oxidation reaction occurs, the exhaust gas must be pre-heated to about 400 ^oF to 800 ^oF. Below this temperature range, the reaction rate drops sharply, and effective oxidation of CO is no longer feasible.

Sulfur and other compounds in the exhaust may foul the catalyst, leading to decreased activity. 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. Catalyst replacement is usually necessary every five to ten years depending on type and operating conditions.

The cost for catalytic oxidation is $23,723 per ton of CO removed. This cost level is considered to be economically infeasible for BACT. In addition to cost, catalytic oxidation would lead to increased downtime for catalyst washing and would present hazardous waste concerns during catalyst disposal. Due to the high cost and concerns with downtime and hazardous material disposal, catalytic oxidation is not selected as BACT for control of CO emissions from the turbines. An RBLC search of 41 analyses indicated that while there are entries in the RBLC of simple cycle turbines constructed with catalytic oxidation, these entries are either driven by LAER (which cannot be used to establish BACT) or are a case-by-case determination. There are no adverse economic, environmental or energy impacts associated with the proposed control alternative.

Good combustion practices and design are acceptable as BACT for CO emissions.

PM_{10} BACT Review

The use of natural gas is in and of itself a highly efficient method of controlling emissions. The maximum estimated PM_{10} emission rate is 0.0093 lbs/MMBTU (HHV) from the turbines. Based on a review of 57 cases in EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, there are no BACT requirements for add-on particulate control requirement for natural gas-fired combustion turbines. Therefore, BACT for PM_{10} emissions from the combustion turbines is the use of a low ash fuel (natural gas) and efficient combustion. There are no adverse environmental or energy impacts associated with the control alternative. Additionally, the proposed turbines will be subject to NSPS Subpart GG, which contains no specific particulate emission limits.

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

Start-up / Shutdown BACT Review

The turbine manufacturer would not guarantee in writing a time frame for start-up and shutdown. Emissions during start-up were calculated assuming a 2-hour period but with a reasonable expectation that full pre-mixed operation can occur in a fraction of that time.

The BACT analysis for start-up and shutdown continued from the normal operation BACT analysis, determining a cost per ton of pollutant removed. Catalytic oxidation was used for CO emissions and SCR for NOx emissions. Annualized control costs were calculated at $2,041,743 to remove 9 TPY NOx, or $240,376 per ton. Annualized control costs for CO were calculated $1,623,234 to remove 20 TPY CO, or $81,162 per ton. These costs are excessive.

In the absence of manufacturer guarantees, the permit will define "start-up" as being the first two hours of operation. BACT for these periods is acceptable as no add-on controls.

Table 9 – Start-up / Shutdown BACT Limits

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

Part B: Evaluation of Existing Air Quality
&
Part C: Evaluation of PSD increment consumption.
&
Part D: Analysis of compliance with National Ambient Air Quality Standards (NAAQS).

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

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

Modeling conducted by the applicant and reviewed by the DEQ demonstrated that emissions from the facility did not exceed the PSD modeling significance levels.

Modeling Methodology

Modeling was conducted using AERMOD PRIME (version 04300) to determine if a significant impact area for each pollutant occurred. A Cartesian receptor grid was used in the modeling analysis. Receptors were placed at 50-meter intervals along the site fence line, beyond which receptor grids were defined. A grid with 100-meter spacing was used from the plant site to a distance of one kilometer, 500-meter spacing was used from one kilometer to five kilometers, and 1000-meter spacing was used from five kilometers to 10 kilometers.

Surface meteorological data and upper air data for 1986, 1987, 1988, 1990, and 1991 from the Tulsa airport were used to produce the meteorological input files for the modeling analysis. The anemometer height of NWS Station Number 13968 was 7.01 meters. The meteorological data were pre-processed in AERMET using land-use/micromet parameters, i.e., albedo, Bowen ratio, and surface roughness provided by the Oklahoma DEQ. A summary of these parameters is provided below.

Table 10 - AERMET Land-Use Parameters

Property	Winter Dec-Jan-Feb	Spring Mar-Apr-May	Summer Jun-Jul-Aug	Autumn Sep-Oct-Nov
Albedo Values	0.55	0.13	0.16	0.15
Bowen Ratio Average Values	1.40	0.50	0.40	0.85
Surface Roughness Values	0.26	0.52	0.75	0.43

A downwash analysis was completed using EPA's BPIP model. The site is located in a rural area and the only buildings that could potentially affect the emissions from the facility are the turbine structures. The downwash analysis was completed to insure that wake effects from the structures at the site will not cause the emissions from the facility to result in concentrations that exceed the PSD Class II increments or NAAQS.

United States Geological Survey Digital Elevation Models (DEM) were obtained and terrain elevations in the vicinity of the site were taken from the DEM and entered into the model input files. Terrain elevations were selected as the highest of each four surrounding points.

The turbines will normally be operated in the 75-100% load range except during start-up, shutdown, and malfunctions. Emissions from the turbines in this load range are highest at 100% load; therefore, emissions of NOx, CO, and PM_{10} were modeled at 100% load. The stack parameters following and the emission rates on the following page were used in the modeling analysis.

Table 11 - Stack Parameters

Source	Height	Diameter	Temperature	Exhaust Velocity
Unit 3	92 feet	22.0 feet	945°F	118 ft/sec
Unit 4	92 feet	22.0 feet	945°F	118 ft/sec

Modeling Results
The modeling results shown are the highest resulting concentrations and show that the proposed turbines will not result in a significant impact on ambient air quality in the vicinity of the site. The PM_{10} 24-hour estimate is actually the highest sixth high for the entire five-year period modeled, per Section 7.2.1.1.b of Appendix W to 40 CFR 51.

Table 12 - Significance Level Comparisons

Pollutant	Averaging Period	Year	Maximum Concentrations (μg/m³)	Significance Levels (μg/m³)
NO_2	Annual	1986, 1990	0.06	1
CO	8-hour	1986	54.60	500
	1-hour	1988	130.78	2000
PM_{10}	Annual	1990	0.017	1
	24-hour	5-year	1.05	5

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

Part E: Pre- and post-construction ambient monitoring.

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

Table 13 - Comparison of Modeled Impacts to Monitoring Exemption Levels

Pollutant	Monitoring Exemption Levels		Ambient Impacts	
	μg/m³	Averaging Time	μg/m³	Averaging Time
NO_2	14	annual	0.06	annual
CO	575	8-hour	54.60	8-hour
PM_{10}	10	24-hour	1.05	24-hour
VOC / Ozone	100 TPY Added VOC		4.0 TPY Added VOC	

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

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

Growth Impacts
A growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the facility and to estimate emissions resulting from that associated growth. Associated growth includes residential and commercial/industrial growth resulting from the new facility. Residential growth depends on the number of new employees and the availability of

housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. Although it is possible that additional personnel may be employed to aid the operation and maintenance of these peaking units, additional growth from this project is expected to be minimal.

Soils and Vegetation

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

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

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

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

Visibility Impairment

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

Part G: Evaluation of Class I area impacts.

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

Class I MSLs (Recommended)

Pollutant	**Modeling Significance Level ($\mu g/m^3$)**		
	Annual	**24-hr**	**3-hr**
SO_2	0.03	0.07	0.48
PM_{10}	0.08	0.27	-
NO_2	0.03	-	-

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

There is no Class I area within 200 km of the facility. Given the great distance and the contribution of only 51 TPY of NO_X and 20 TPY of PM_{10} from this project, no visibility analysis or increment consumption is performed.

VI. OKLAHOMA AIR POLLUTION CONTROL RULES

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

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-4 (New Source Performance Standards) [Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they existed on September 1, 2005, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, Subpart

BBBB, Subpart DDDD, Subpart HHHH and Appendix G. NSPS requirements are addressed in the "Federal Regulations" section.

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

OAC 252:100-8 (Operating Permits (Part 70)) [Applicable]
This facility meets the definition of a major source since it has the potential to emit regulated pollutants in excess of 100 TPY. As such, a Title V (Part 70) operating permit is required. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. The project is a significant modification to the facility and requires that an application for modification of the Title V (Part 70) operating permit be submitted within 180 days of commencement of operation of the new units. Insignificant activities mean individual emission units that either are on the list in Appendix I <u>or</u> whose actual calendar year emissions do not exceed the following limits:

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

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

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 or operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility.

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

OAC 252:100-19 (Particulate Matter) [Applicable]
Subchapter 19 regulates emissions of particulate matter from fuel-burning equipment. Particulate emission limits are based on maximum design heat input rating. Fuel-burning equipment is defined in §19-1.1 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. Thus, the turbines are subject to the requirements of this subchapter, and the emission factors identified in Section

IV above demonstrate compliance. Applicability of this subchapter to existing equipment is unchanged by this project.

Equipment	Maximum Heat Input	PM Emission Limit	Potential PM Emissions
Turbines (2)	1,078 MMBTUH each	0.20 lbs/MMBTU	0.009 lb/MMBTU

OAC 252:100-25 (Smoke, Visible Emissions, and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The turbines will remain compliant with this rule by using good combustion practices and utilizing pipeline-quality natural gas as fuel. Applicability of this subchapter to existing equipment is unchanged by this project.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions 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]
Applicability of this subchapter to existing equipment is unchanged by this project.
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lbs/MMBTU heat input, three-hour rolling average. The turbines will be fired with pipeline quality natural gas having a maximum sulfur content of 5.0 grains per 100 standard cubic feet and an annual average sulfur content of 0.25 grains per 100 standard cubic feet of gas (equivalent to 0.0008 wt% sulfur). Based on a gross heating value of 1,020 BTU/SCF and assuming stoichiometric conversion to sulfur dioxide, the sulfur content results in approximately 0.014 lbs of SO_2/MMBTU.
Part 5 also requires an opacity monitor and sulfur dioxide monitor for equipment rated above 250 MMBTUH. Since the turbines are limited to natural gas only, they are exempt from the opacity monitor requirement. Equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitor requirement. Based on the pipeline-quality natural gas requirement, the turbines will be exempt from the sulfur dioxide monitoring requirement.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
Applicability of this subchapter to existing equipment is unchanged by this project.
This subchapter limits nitrogen oxide emissions calculated as nitrogen dioxide from any new gas-fired fuel-burning equipment with a rated heat input greater than or equal to 50 MMBTUH to 0.20 lbs/MMBTU, three-hour average. As a worst case, maximum emissions of 186 lbs/hr occur during cold start-up. Assuming 1,078 MMBTUH during that period yields emissions of 0.17 lbs/MMBTU, in compliance with the standard of Subchapter 33. For purposes of comparison only, “normal” operation has emissions of only 0.03 lbs/MMBTU, and the annual average of 42.2 lbs/hr calculated in the Emissions Section yields a rate of 0.039 lbs/MMBTU.

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) [Part 7 Applicable]
Applicability of this subchapter to existing equipment is unchanged by this project.
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. There are no storage tanks planned for this project.
Part 5 limits the VOC content of coatings used in coatings lines or operations. This facility will not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion. The turbines are designed to provide essentially complete combustion of organic materials.

OAC 252:100-39 (VOC in Nonattainment and Former Nonattainment Areas)
[Not Applicable to This Project]
Applicability of this subchapter to existing equipment is unchanged by this project.
Part 3 affects petroleum refinery operations, none of which occur at this facility.
Part 5 affects petroleum liquid storage in external floating roof tanks, none of which occurs at this facility.
Part 7 contains rules affecting specific processes. No part of the proposed project is subject to any of the sections of Part 7.

OAC 252:100-41 (Hazardous Air Pollutants (HAP)) [Not Applicable to This Project]
Applicability of this subchapter to existing equipment is unchanged by this project.
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they existed on September 1, 2005, 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, 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, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, YYYY, ZZZZ, AAAAA, BBBBB, CCCCC, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS, and TTTTT are hereby adopted by reference as they existed on September 1, 2005. These standards apply to both existing and new sources of HAP. These requirements are covered in the “Federal Regulations” section.

Part 5 was a **state-only** requirement governing sources of toxic air contaminants that have emissions exceeding a *de minimis* level. However, Part 5 of Subchapter 41 has been superseded by OAC 252:100-42, effective June 15, 2006.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
Part 5 of OAC 252:100-41 was superseded by this subchapter. Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

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

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

OAC 252:100-7	Minor Sources	not in source category
OAC 252:100-11	Alternative Reduction	not eligible
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Feed & Grain Facility	not in source category
OAC 252:100-47	Landfills	not type of emission unit

VII. 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 MMBTUH heat input with emissions greater than 100 TPY. PSD review was discussed in Section V.

NSPS, 40 CFR Part 60 [Subparts A and GG Applicable]
The current project does not affect the applicability of subparts addressed in the existing operating permit.

Subpart A requires the submittal of several notifications for NSPS-affected facilities. Within 30 days after starting construction or modification of any affected facility, the Facility must notify DEQ that construction has commenced. A notification of the actual date of initial start-up of any affected facility shall be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial start-up of the facility. The Facility must notify DEQ at least 30 days prior to any initial performance test and must submit the results of the initial performance tests to DEQ.
Subpart GG (Stationary Gas Turbines) affects stationary gas turbines with a heat input at peak load of greater than or equal to 10.7 gigajoules per hour (10 MMBTUH) based on the lower heating value (LHV) of the fuel and that commenced construction, reconstruction, or modification after October 3, 1977. The new turbines have HHV heat input capacities of 1,078 MMBTUH at peak load and are subject. The turbines are governed by 40 CFR 60.332(b) and must satisfy the NO_X standard set forth in §60.332(a)(1). As applied to these turbines, the formula yields a limit of 75 ppmvd. For NO_X emissions, the BACT requirement of 9 ppmvd is more stringent than Subpart GG and is applicable. Testing fuel for nitrogen content was addressed in a letter dated May 17, 1996, from EPA Region 6. Monitoring of fuel nitrogen content shall not be required when pipeline-quality natural gas is the only fuel fired in the turbine. Performance testing by Reference Method 20 is required.

Sulfur dioxide standards specify that no fuel that exceeds 0.8% by weight sulfur shall be used nor shall exhaust gases contain in excess of 150 ppm SO_2. For fuel supplies without intermediate bulk storage, the owner or operator shall either monitor the fuel nitrogen and sulfur content daily or develop custom schedules of fuel analysis based on the characteristics of the fuel supply; these custom schedules must be approved by the Administrator before they can be used for compliance with monitoring requirements. The EPA Region 6 letter referenced above also states that when pipeline-quality natural gas is used exclusively, acceptable monitoring for sulfur is a quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly "stain tube" analysis. DEQ no longer accepts "stain tubes," so monitoring for sulfur is proposed as a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 0.25 grains/100 scf or less.
Subpart KKKK (Stationary Combustion Turbines) affects stationary gas turbines rated at 10 MMBTUH heat input or greater that commenced construction, modification, or reconstruction after February 18, 2005. Although these turbines are being relocated to the Riverside 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 other than trace amounts of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, mercury, radionuclides, or vinyl chloride.

NESHAP, 40 CFR Part 63 [Not Applicable]
Only those subparts affected by the current project are addressed. At the time of last renewal, there were no affected subparts at the existing facility.
Subpart YYYY (Stationary Combustion Turbines) sets forth emission limitations and operating limitations for formaldehyde from existing, new, and reconstructed stationary combustion turbines located at major sources of HAP emissions. As previously mentioned, these turbines were initially constructed prior to 2003 and are considered existing sources. The facility purchased these units from the original owner, but a change in ownership is not sufficient to classify a turbine as new or reconstructed per §63.6090(a)(1). Per §63.6090(b)(4), existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart or of Subpart A of this part and do not require initial notification.
Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters) sets forth emission and operating limitations for existing, new, and reconstructed industrial, commercial and institutional boilers and process heaters located at a major source of HAP. The combustion turbines are simple cycle units that do not operate with heat recovery steam generators (HRSGs) or duct burners. No other units besides the combustion turbines are associated with this project. The existing boilers are electric generating units with capacity greater than 25 MW, and are not subject, per 40 CFR 63.7491(c). As a result, this subpart does not apply.

CAM, 40 CFR Part 64 [Not Applicable]
Applicability of this subchapter to existing equipment is unchanged by this project.
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

Dry low-NO_X burners are not active control devices, so the turbines are not subject to CAM monitoring.

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

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
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. U.S. EPA has confirmed that the regulating agency (Oklahoma DEQ) can waive this requirement and DEQ has done so. The applicant has submitted an 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 (NOx Requirements) [Not Applicable]
This part provides for NOx limitations and reductions for coal-fired utility units. Since the units in this project will fire natural gas only, they are exempt.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subpart A and F Applicable]
Applicability of this subchapter to existing equipment is unchanged by this project.
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.
Conditions are included in the standard conditions of the permit to address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; § 82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.
This facility does not utilize any Class I & II substances.

VIII. COMPLIANCE

Tier Classification and Public Review
This application has been determined to be **Tier II** based on the request for a construction permit for a significant modification to a Part 70 source.

The applicant published the "Notice of Filing a Tier II Application" in the *Tulsa World* on September 12, 2006. The notice stated that the application was available for public review at the DEQ Regional Office at Tulsa, Oklahoma. A "Notice of Tier II Draft Permit" was published in the *Tulsa World* on December 14, 2006. The notice stated that the Draft was available for review at the DEQ Regional Office at Tulsa, at the Air Quality Division office in Oklahoma City, and on the DEQ website. Information on all permit actions is available for review by the public on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*. Only one comment was received. The electronic comment provided by the facility is reproduce verbatim as follows.

Comment. Special Condition 7 is to detailed. Can't we just say "The holder of this permit shall comply with the requirements of Title 40 Code of Federal Regulations Part 75 (40 CFR Part 75)." I request this change because the units will meet the Low Mass Emissions requirements of 75.19.
Response. The reference is to Specific Condition #9. The original wording was intended to cover the actual operating conditions of the turbines. As currently proposed, the turbines should meet the requirements for exception methodologies under 40 CFR 75.19. Because of this, DEQ agrees that generic language similar to that suggested by the facility is appropriate.

A public meeting was scheduled for 6:00 PM, January 18, 2007, at the Jenks Public Library. Due to weather conditions, the Library closed at 5:00 PM on that day, so the meeting was rescheduled for 6:30 at the Jenks City Hall, across the street from the Library. The only persons attending the meeting were Herb Neumann, permit writer from the DEQ Regional Office at Tulsa, and Mark Radzinski, Environmental Supervisor for PSO's Riverside Station. Because of the weather and scheduling difficulties, the comment period was extended to the close of business on Friday, January 19, 2007. The proposed permit was sent to EPA Region VI for their comments on January 31, 2007. They had no comments.

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

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

IX. SUMMARY

Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance and enforcement issues concerning this facility. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

PSO Riverside Power Station **Permit No. 2003-360-C (M-1)(PSD)**
Addition of Two Combustion Turbines

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on August 17, 2006. The Evaluation Memorandum dated March 21, 2007, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating 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 emission limitations. [OAC 252:100-8-6(a)]

Equipment and emissions authorized under existing operating permit 2003-360-TVR for EUG 1, EUG 2, EUG 3, EUG 4, and Insignificant Activities, are not altered by this construction permit and remain as stated in the existing permit.

EUG 5 Simple Cycle Combustion Turbines
Turbines identified as emission units 3 and 4 are GE7EA units constructed before 2003. These are peaking units, with short-term emission standards authorized as follow for each unit.

Table 1

Pollutant	**Lb/hr**	**Lb/MMBTU**	**ppmvd @ 15% O_2**
NO_X [a]	35.0	0.039 [d]	9
CO [b]	59.0		25
VOC	2.0		N/A
SO_2 [c]	15.0		N/A
PM_{10}	10.0		N/A
Lead	0.0005		N/A
H_2SO_4	0.12		N/A

a) 3-hour rolling average calculated with normal operating data excluding start-up and shutdown.
b) 1-hour rolling average calculated with normal operating data excluding start-up and shutdown.
c) Based on maximum short-term concentrations of 5 grains of sulfur per 100 dscf.
d) 12-month rolling average.

Start-up and shutdown operations have authorized emission rates summarized in Table 2, based on the following definitions and assumptions.

a) **Start-up** begins when fuel is supplied to the Gas Turbine and ends when the gas turbine reaches DLN mode (as directed by the control system).
b) **Shutdown** begins when the turbine exits the DLN mode and ends with the termination of fuel flow to the turbine.
c) **Cold Start** is a start-up beginning more than 24 hours after the same unit shutdown.
d) **Warm Start** is a start-up beginning less than 24 hours after the same unit shutdown.

e) An **operating cycle** consists of 12.82 hours of operation, no more than 2 of which are start-up hours and no more than one of which is a shutdown hour.
f) **Average operations** consist of three warm starts for every cold start.

Table 2

Event	Maximum Duration	Emissions (Lbs)	
		NO_x	CO
Cold start-up	2 hours	372	627
Warm start-up	2 hours	114	192
Shutdown	1 hour	20.3	34.2

Annual emissions are authorized for 2,000 hours of operation for each unit. The total of 4,000 hours may be utilized by either unit, with total emissions for combined units as follow. Adding the start-up/shutdown conditions to the short-term emission values described in Table 1 yields average hourly emissions of 42.2 lbs/hr of NO_X and 71.3 lbs/hr of CO, and the annual values shown in Table 3.

Table 3

Pollutant	TPY
NO_X	84.4
CO	143
VOC	4.0
SO_2*	1.50
PM_{10}	20.0
Lead	0.001
H_2SO_4	0.24

* Based on long-term sulfur content of 0.25 grains per 100 dscf.

2. Emission limits authorized in Specific Condition No. 1 (SC #1) shall be met by the following means. [OAC 252:100-8-6(a)]

a) A surrogate limit of fuel consumption equal to 2,000 hours of operation at 1,078 MMBTUH for each unit shall not be exceeded. Thus, fuel usage for both turbines is limited to a combined consumption of 4,312 MMMBTU/year (12-month rolling total).
b) Compliance with the start-up and shutdown limits shall be demonstrated through performance testing. CEMs data may be used where available and testing of emissions during initial performance testing shall be performed if CEMs data are not available.

3. Each combustion turbine at the facility shall have a permanent (non-removable) identification plate attached that shows the make, model number, and serial number. [OAC 252:100-8-6]

4. Emissions from each turbine unit shall be controlled by properly operated and maintained Dry Low-NOx Combustors (DLN) to satisfy BACT requirements. [OAC 252:100-8-5 (d)(1)(A)]

5. 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 Part 60, Subpart GG]

a) 60.332: Standard for nitrogen oxides. Monitoring of fuel nitrogen content under NSPS Subpart GG shall not be required while commercial quality natural gas is the only fuel fired in the turbines.
b) 60.333: Standard for sulfur dioxide. Since pipeline-quality natural gas will be used exclusively, monitoring for sulfur is proposed as a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 0.25 grains/100 scf or less.
c) 60.334: Monitoring of operations
d) 60.335: Test methods and procedures

6. Performance testing shall be conducted on each new turbine within 180 days following commencement of operations of each new turbine. [OAC 252:100-43]

a) The following reference methods specified in 40 CFR 60 shall be used.
Method 1: Sample and Velocity Traverses for Stationary Sources.
Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4: Determination of Moisture in Stack Gases.
Method 7 or 7E: Determination of Nitrogen Oxide Emissions From Stationary Sources
Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources
Method 18 or 25A: Determination of Volatile Organic Compounds Emissions From Stationary Sources
Method 201/201A: Determination of PM_{10} Emissions
Method 202: Determination of Condensable Particulate Emissions
b) Performance testing shall be conducted while the units are operating under representative conditions within 10% of maximum production rate.
c) A protocol describing the testing plan shall be submitted to the Air Quality Division Regional Office at Tulsa at least 30 days prior to testing.
d) A written report documenting results of emissions testing shall be submitted within 60 days of completion of on-site testing.

7. NO_X and CO concentrations listed in Table 1 of Specific Condition No.1 shall not be exceeded except during periods of start-up, shutdown or maintenance operations. Start-up periods shall not exceed two hours per occurrence and shutdown periods shall not exceed one hour per occurrence. NO_X emissions during normal operations are based on a 3-hour rolling average, so calculation of NO_X emissions that overlap start-up or shutdown periods may appear to exceed "normal" limits (35 lbs/hr and 9 ppmvd). Only those emissions within the normal operating period shall be used in determining short term exceedances.

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

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

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

a) Total fuel consumption in MMBTU for the turbines (monthly and 12-month rolling totals).
b) Sulfur content of natural gas (one of the methods from Condition 5 (b)).
c) CEMS data required by the Acid Rain program.
d) Records required by NSPS Subpart GG.

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

a) 40 CFR Part 60, NSPS except for Subpart GG
b) 40 CFR Part 61, NESHAP
c) 40 CFR Part 63, NESHAP
d) 40 CFR Part 64, Compliance Assurance Monitoring
e) 40 CFR Part 68, Chemical Accident Prevention Provisions
f) OAC 252:100-19 (PM), all but Sections 1 and 4.

12. No later than 30 days after each anniversary date of the issuance of the original Title V operating permit for this facility (May 12, 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. The following specific information is required to be included. [OAC 252:100-8-6 (c)(5)(A) & (D)]

a) Excess emissions and actions taken to correct the underlying cause (each occurrence).
b) Gaps in recordkeeping and reasons for each (each occurrence).

13. No later than 180 days after the start of operation of these turbines, the permittee shall submit an application to DEQ to incorporate them into the facility's Title V operating permit.

TITLE V (PART 70) PERMIT TO OPERATE / CONSTRUCT
STANDARD CONDITIONS
(December 6, 2006)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with Title V of the federal Clean Air Act (42 U.S.C. 7401, et seq.) 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, for revocation of the approval to operate under the terms of this permit, or for denial of an application to renew this permit. All terms and conditions (excluding state-only requirements) are enforceable by the DEQ, by EPA, and by citizens under section 304 of the Clean Air Act. This permit is valid for operations only at the specific location listed.
[40 CFR §70.6(b), OAC 252:100-8-1.3 and 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. [OAC 252:100-8-6 (a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

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

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. Oral notifications (fax is also acceptable) shall be made to the AQD central office 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 the permittee becomes aware of the exceedance. 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. Every written report submitted under OAC 252:100-8-6 (a)(3)(C)(iii) shall be certified by a responsible official. [OAC 252:100-8-6 (a)(3)(C)(iii)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. Unless a different retention period or retention conditions are set forth by a specific term 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), 8-6 (c)(1), and 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 as existing at the time of sampling or measurement.

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

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. [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 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.

F. Submission of quarterly or semi-annual reports required by any applicable requirement that are duplicative of the reporting required in the previous paragraph will satisfy the reporting requirements of the previous paragraph if noted on the submitted report.

G. Every report submitted under OAC 252:100-8-6 and OAC 252:100-43 shall be certified by a responsible official. [OAC 252:100-8-6 (a)(3)(C)(iv)]

H. Any owner or operator subject to the provisions of NSPS shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility or any malfunction of the air pollution control equipment. [40 CFR 60.7 (b)]

I. Any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and other information required by the subpart recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance, and records. [40 CFR 60.7 (d)]

J. 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 preventative or corrective measures adopted. [OAC 252:100-8-6 (c)(4)]

K. All testing must be conducted by methods approved by the Division Director under the direction of qualified personnel. 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. [40 CFR §70.6(a), 40 CFR §51.212(c)(2), 40 CFR § 70.7(d), 40 CFR §70.7(e)(2), OAC 252:100-8-6 (a)(3)(A)(iv), and OAC 252:100-43]

The reporting of total particulate matter emissions as required in Part 70, PSD, OAC 252:100-19, and 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). [US EPA Publication (September 1994). PM_{10} Emission Inventory Requirements - Final Report. Emission Inventory Branch: RTP, N.C.]; [Federal Register: Volume 55, Number 74, 4/17/90, pp.14246-14249. 40 CFR Part 51: Preparation, Adoption, and Submittal of State Implementation Plans; Methods for Measurement of PM_{10} Emissions from Stationary Sources]; [Letter from Thompson G. Pace, EPA OAQPS to Sean Fitzsimmons, Iowa DNR, March 31, 1994 (regarding PM_{10} Condensables)]

L. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 CFR Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-4-5 and OAC 252:100-41-15]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

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

B. The certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period; and a statement that the facility will continue to comply with all applicable requirements.

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

C. Any document required to be submitted in accordance with this permit shall be certified as being true, accurate, and complete by a responsible official. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification 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, -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 10 days after such date.

[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, 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 as necessary to remedy deficiencies 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.

C. If "grandfathered" status is claimed and granted for any equipment covered by this permit, it shall only apply under the following circumstances: [OAC 252:100-5-1.1]

(1) It only applies to that specific item by serial number or some other permanent identification.
(2) Grandfathered status is lost if the item is significantly modified or if it is relocated outside the boundaries of the facility.

D. To make changes other than (1) those described in Section XVIII (Operational Flexibility), (2) administrative permit amendments, and (3) those not defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII), the permittee shall notify AQD. Such changes may require a permit modification. [OAC 252:100-8-7.2 (b)]

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

(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.

SECTION XIV. EMERGENCIES

A. Any emergency and/or 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)]

B. 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. [OAC 252:100-8-2]

C. An emergency shall constitute an affirmative defense to an action brought for noncompliance with such technology-based emission limitation if the conditions of paragraph D below are met.
[OAC 252:100-8-6 (e)(1)]

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), (a)(3)(C)(iii)(I) and (IV)]

(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;
(4) the permittee submitted timely notice of the emergency to AQD, pursuant to the applicable regulations (i.e., for emergencies that pose an "imminent and substantial danger," within 24 hours of the time when emission limitations were exceeded due to the emergency; 4:30 p.m. the next business day for all other emergency exceedances). *See OAC 252:100-8-6(a)(3)(C)(iii)(I) and (II).* 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; and
(5) the permittee submitted a follow up written report within 10 working days of first becoming aware of the exceedance.

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)]

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. [OAC 252:100-8-2]

(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.

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]

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 7 days, or 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 subsection.[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) No person shall cause or permit the discharge of emissions such that National Ambient Air Quality Standards (NAAQS) are exceeded on land outside the permitted facility. [OAC 252:100-3]
(2) 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]
(3) 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]
(4) For all emissions units not subject to an opacity limit promulgated under 40 CFR, Part 60, NSPS, 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. [OAC 252:100-25]
(5) 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]
(6) 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]
(7) 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)]

(8) 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.
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.
(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 Sources' 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 Oklahoma Administrative Code 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 Code of Federal Regulations (CFR) § 70.7 (h)(1). This public notice shall include notice to the public that this permit is subject to Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 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 CFR § 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 CFR § 70.8(a) and (c).
(5) The DEQ complies with 40 CFR § 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 CFR § 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 CFR § 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]

PART 70 PERMIT

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

Permit Number: 2003-360-C (M-1)(PSD)

PUBLIC SERVICE COMPANY OF OKLAHOMA,

having complied with the requirements of the law, is hereby granted permission to construct two combustion turbines at the Riverside Power Station located at 116th Street and the Arkansas River, having the legal description of Section 32, T18N, R13E, Tulsa, Tulsa County, OK,

subject to standard conditions dated December 6, 2006, and specific conditions, both attached.

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

Director, Air Quality Division **Date**

March 27, 2007

Stuart Solomon, President and Chief Operating Officer
Public Service Company of Oklahoma
212 E. Sixth Street
Tulsa, OK 74119

Subject: Construction Permit No. **2003-360-C (M-1)**
Install Two Combustion Turbines at Riverside Power Station

Dear Mr. Solomon:

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

Also note that you are required to annually submit an emission inventory for this facility. An emission 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 Emission Inventory Staff at 405-702-4100.

Thank you for your cooperation in this matter. If we may be of further service, please contact our office at (918) 293-1600. Air Quality personnel are located in the DEQ Regional Office at Tulsa, 3105 E. Skelly Drive, Suite 200, Tulsa, OK, 74105.

Sincerely,

Herb Neumann
AIR QUALITY DIVISION

Encl.