OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **December 12, 2006**

TO: Dawson Lasseter, P.E., Chief Engineer, Permits Section

THROUGH: Phil Martin, P.E., New Source Permits Unit

THROUGH: Grover Campbell, P.E., Existing Source Permits Unit

THROUGH: Peer Review

FROM: Richard Kienlen, P.E., New Source Permits Unit

SUBJECT: Evaluation of Permit Application No. **2001-205-C (M-1)(PSD)**
Energetix, LLC
Lawton Energy Cogen Facility
Section 31, T2N, R12W, Lawton, Comanche Co. (≈ 34.602° N, -98.501° W)
Location: Take Lee Blvd. exit from I-44. Proceed west on Lee Blvd. to Ard St. The plant is northwest of the intersection of Lee Blvd. and Ard Street.

SECTION I. INTRODUCTION

Energetix, L.L.C. (Energetix), proposes to construct and operate a new electric power generation facility (SIC Code 4911) on a 26-acre site in Comanche County. Energetix has requested this modification of the initial construction Permit Number 2001-205-C (PSD) to change the power source from two (2) G.E. Frame 7EA combustion turbines to one (1) Siemens SSC6-5000F. The facility will operate as a qualifying cogeneration facility pursuant to the Public Utility Regulatory Policy Act (PURPA), and deliver the electricity generated via existing electric transmission systems. Waste heat from exhaust gases will be used to generate steam, which can be both sold to local industries and used to generate additional electricity. Terrain in the area around the facility has elevation changes of approximately twenty feet. Grade elevation of the main structures and supporting structures will be about 1,207 feet above mean sea level (MSL).

The power plant will have the potential to emit greater than 100 tons per year (tpy) of at least one regulated pollutant and is on the list of 28 specifically listed industrial source categories. Therefore, the power plant will be a major stationary source and is subject to Prevention of Significant Deterioration (PSD) permitting. The PSD regulations require Best Available Control Technology (BACT) and air quality analyses for each pollutant for which the project is significant. Once the power plant is established as a major source, the other pollutants are compared to the PSD Significant Emission Rate (SER) thresholds. The following table lists the potential emission rates for each PSD regulated pollutant.

Old Emission Rates for PSD Regulated Pollutants (Two GE 7EAs)

Pollutant	Facility Total Emission Rate (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review?
CO	948	100 [A]	Yes
NO_X	190	100	Yes
PM_{10}	202	15	Yes
VOC	122	40	Yes
SO_2	23	40	No
Sulfuric Acid Mist	6.8	7	No

[A] Potential CO emissions greater than 100 tpy establish this new facility as a PSD major stationary source.

New Emission Rates for PSD Regulated Pollutants (One SSC6-5000F)

Pollutant	Facility Total Emission Rate (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review?
CO	420.04	100 [A]	Yes
NO_X	177.18	100	Yes
PM_{10}	105.04	15	Yes
VOC	39.05	40	No
SO_2	10.22	40	No
Sulfuric Acid Mist	2.98	7	No

[A] Potential CO emissions greater than 100 tpy establish this new facility as a PSD major stationary source.

The above emission rates take into account the use of Selective Catalytic Reduction (SCR) to reduce NO_x emissions to 3.5 ppm at 15% O_2 with duct burners firing and to limit ammonia slip to 10 ppmvd with or without duct burners firing.

SECTION II. FACILITY DESCRIPTION

Upon completion, the facility will consist of one (1) Siemens SSC6-5000F combustion turbine (CT) equipped with a duct burner (DB), one (1) heat recovery steam generator (HRSG), one (1) steam turbine (ST), one (1) auxiliary boiler, one (1) diesel emergency generator, one (1) diesel-fired water pump, and cooling towers. Each CT/HRSG/ST combination is commonly termed a combined cycle combustion turbine (CCCT). The CT has a nominal heat input of approximately

1,911 million British thermal units per hour (MMBtu/hr) higher heating value (HHV), while the DB has a nominal heat input of 560 MMBtu/hr (HHV). The boiler, generator engine and fire water pump engine have heat inputs of 360, 7, and 0.9 MMBtu/hr, respectively. The CT and DB will fire only pipeline-quality natural gas. In addition to the CT and engines, the facility will include a balance of plant equipment and systems such as natural gas metering systems; handling systems; instrumentation and control systems; water treatment, storage and handling systems; transformers; and administration and warehouse/maintenance buildings.

The use of natural gas at the facility provides a cleaner and more environmentally-friendly means of electricity generation than less efficient coal- and oil-fired power plants. The inclusion of an HRSG and other heat recovery equipment in the process increases the efficiency of this power plant, allowing for the production of more electricity while generating fewer emissions. Use of cogeneration facilities has been encouraged by the U.S. Environmental Protection Agency (U.S. EPA) in order to achieve minimized environmental impact through improved efficiency.

Operating Parameters

Parameter	Old (GE 7EA)	New (SSC6-5000F)
Stack Height (ft)	150	150
Exit Velocity (ft/sec)	59.17	70.8
Stack Temperature (°F)	176.9	176.9

SECTION III. EMISSIONS

Emission factors for the turbine are based on data provided by Energetix and the manufacturer. NO_x and CO values for the turbine are based on parts per million by volume, dry basis, corrected to 15% oxygen. Energetix requests that the CT with duct burner and associated HRSG be authorized to operate every hour of the year. The auxiliary boiler emissions are based on 3,000 hrs/yr and data provided by Energetix: 0.036 lbs/MMBtu for NO_x, 0.074 lbs/MMBtu for CO, and 0.0069 lbs/MMBtu for PM_{10}; SO_2 and VOC emissions are based on AP-42 (7/98), Table 1.4-2. The emergency diesel generator and fire water pump will each be limited to 500 hours per year with emissions based on AP-42 (10/96), Tables 3.4-1 and 3.3-1, respectively. All particulate emissions are assumed to be PM_{10}, and based on published emission factors for natural gas combustion, estimated lead emissions from this project are negligible. The following table shows the facility's estimated emissions.

Pollutant	CT w/Duct Burner		Auxiliary Boiler		Emergency Diesel Generator		Diesel Fire Water Pump		Cooling Tower	
	lbs/hr	TPY	lbs/hr	TPY	lbs/hr	TPY	lbs/hr	TPY	lbs/hr	TPY
NO_X	33.76	147.87	12.96	19.44	31.18	7.79	8.31	2.08	---	---
CO	86.29	377.95	26.64	39.96	6.72	1.68	1.79	0.45	---	---
VOC	8.07	35.35	1.94	2.91	2.48	0.62	0.66	0.17	---	---
SO_2	2.08	9.09	0.32	0.48	2.06	0.52	0.55	0.14	---	---
PM_{10}	16.64	72.88	2.48	3.73	2.21	0.55	0.59	0.15	6.33	27.7
H_2SO_4	0.68	2.98	---	---	---	---	---	---	---	---

The proposed plant is estimated to emit a maximum of 2.82 tons per year of total HAP and a maximum of 1.15 tpy of any single HAP (i.e., toluene). Since facility-wide HAP emissions are less than the 10/25 tpy thresholds, the facility is considered an area source for HAP emissions. As such, the facility is not subject to the requirements of Section 112(g), including the case-by-case MACT determination requirement.

HAP emission factors for natural gas combustion in the turbine are from AP-42 (4/00), Table 3.1-3. HAP emission factors for the duct burner and auxiliary boiler are from AP-42 (7/98), Table 1.4-3. HAP emission factors for the fire water pump and diesel generator are from AP-42 (10/96), Tables 3.3-2 and 3.4-3, respectively. Hexane emissions from the duct burner and ancillary units are based on an engineering estimate due to the questionable quality of the factors in AP-42. The table below summarizes the facility's HAP emissions.

Maximum HAP Emissions

	Turbine	Duct Burner	Auxiliary Boiler	Emer. Gen. & Fire H_2O Pump	Tanks	Total Facility
Pollutant	**tpy**	**tpy**	**tpy**	**Tpy**	**tpy**	**tpy**
Acetaldehyde	0.39	---	---	<0.00001	---	0.39
Acrolein	0.09	---	---	1.85E-06	---	0.09
Benzene	0.09	0.01	0.0011	0.0016	3.16E-05	0.10
Dichlorobenzene	---	<0.01	0.0006	---	---	0.01
Ethylbenzene	0.22	---	---	---	9.60E-07	0.22
Formaldehyde	0.26	0.18	0.0397	0.0001	---	0.48
Hexane	---	0.05	0.0105	---	6.31E-05	0.06
Toluene	1.14	0.01	0.0018	0.0006	1.11E-05	1.15
Xylenes	0.44	---	---	0.0003	6.26E-06	0.44
Total HAP	**2.63**	**0.25**	**0.0537**	**<<0.01**	**<<0.0001**	**2.94**

SECTION IV. PSD REVIEW

The PSD Review Section did not require any changes to the BACT or air impact evaluation from what was previously conducted for Permit #2001-205-C (PSD). The proposed facility will have potential emissions above the PSD significance levels for NO_x, CO, and PM/PM_{10}. A full PSD review of emissions consists of the following:

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; and
G. Evaluation of Class I area impact.

A BACT analysis is required for each new or physically modified emission unit for each pollutant, which exceeds an applicable PSD Significant Emission Rate (SER). Since the NO_X, CO, and PM_{10} emissions from the proposed power plant exceed the PSD SERs, a BACT analysis is required to assess the appropriate level of control for these emissions from the proposed new sources. Since the same technologies are used to control PM and PM_{10} emissions, any discussion of BACT for PM_{10} emissions is also assumed to address PM emissions.

The U.S. EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether or not the "top-down" approach is used. First, the BACT analysis must consider the most stringent available technologies (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts."

BACT must be at least as stringent as any NSPS applicable to the emission source. After determining whether any NSPS is applicable, the first step in this approach is to determine for the emission unit in question the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically infeasible for the unit in question, the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical or environmental concerns. The remaining technologies are evaluated on the basis of operational and economic effectiveness. Presented below are the five basic steps of a top-down BACT review procedure as identified by the U.S. EPA in the March 15, 1990, "Draft BACT Guidelines":

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

A. Best Available Control Technology (BACT)

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

The emission units for which a BACT analysis is required include the combustion turbine, duct burner, the auxiliary boiler, and the cooling tower. Due to their status as emergency/backup units and/or very limited run time, the emergency diesel generator and the diesel fire water pump are not included in the 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. Energetix identified these technologies and emissions data through a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as EPA's NSR and CTC websites, recent DEQ BACT determinations for similar facilities, and vendor-supplied information.

- The first step in the BACT analysis is to identify all control technologies for each pollutant subject to review. The following list is for the gas turbine with duct burner firing.

Pollutant	**Technology**
NO_X	Selective Catalytic Reduction (SCR) Dry Low NO_x Combustors Selective Non-Catalytic Reduction (SNCR) Water/steam Injection Good Combustion Practices
CO	Catalytic Oxidation Good Combustion Practices
PM_{10}	Good Combustion Practices Fuel Specification: Clean-Burning Fuels

- The second step is to eliminate any technically infeasible control technology. Each control technology for each pollutant is considered, and those that are clearly technically infeasible are eliminated. Since all options in the above table are potentially technically feasible, no option is eliminated in this step.

- In step three, the control technologies are ranked in order of decreasing effectiveness. The following table presents the technologies and their approximate control efficiencies.

Pollutant	**Technology**	**Potential Control Efficiency, %**
NO_X	Selective Catalytic Reduction (SCR) Dry Low NO_x Combustors Selective Non-Catalytic Reduction (SNCR) Water/steam Injection Good Combustion Practices	50-95 40-60 40-60 30-50 Base Case
CO	Catalytic Oxidation Good Combustion Practices	60-80 Base Case
PM_{10}	Good Combustion Practices Fuel Specification: Clean-Burning Fuels	10-30 Base Case

- In step four, the technologies are evaluated on the basis of economic, energy, and environmental considerations.

NO_x Control Technologies

The proposed turbine and duct burner will be subject to NSPS Subparts KKKK and Da, respectively. Subpart KKKK provides a NO_x limit of 15 ppm at 15% O_2 based on a heat input greater than 850 MMBtu/hr. Subpart Da provides an NO_2 emission limit of 1.6 lbs/MW-hr of gross energy output.

Several post-combustion NO_x control technologies are potentially applicable to the facility. These technologies employ various strategies to chemically reduce NO_x to elemental nitrogen (N_2) with or without the use of a catalyst. Potential NO_x control technologies are evaluated in the following subsections.

As part of the BACT evaluation process, a study was also made of the BACTs that have been recently approved in Oklahoma for similar facilities. The study shows that for NO_x and CO emissions, the proposed BACT and level of emissions (ppm) at this site are consistent with other similar combined cycle power plants approved or proposed in Oklahoma.

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. On the catalyst surface, ammonia and nitric oxide (NO) react to form diatomic nitrogen and water. The overall chemical reaction can be expressed as:

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

When operated within the optimum temperature range of 575 to 750 ^oF, the reaction can result in removal efficiencies between 50 and 95 percent.

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.

The use of SCR technology poses additional environmental and health risks due to the potential for NH_3 slip or accidental release. To limit the potential environmental hazards, ammonia slip will be limited to 10 ppm with or without the duct burner firing.

Energetix proposes NO_X BACT limits (at 100% load) of 3.5 ppmvd at 15% O_2 for the turbine with SCR. Final combined turbine/duct burner emissions are also expected to be less than 3.5 ppmvd at 15% O_2. Since Energetix proposes SCR as BACT, no further control technology method analyses are addressed; just process information is provided. This level of BACT exceeds or equals current Oklahoma BACT determinations.

NO_xOUT is a process in which aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600 to 1,900 ^oF. In addition, there are catalysts available which can expand the range in which the reaction can occur.

The advantages of the system are low capital and operating costs and catalyst, which are not toxic or hazardous. Disadvantages include the formation of ammonia from excess urea treatment and/or improper use of reagent catalyst and plugging of the cold end downstream equipment from the possible reaction of sulfur trioxide and ammonia.

The NO_xOUT process is limited by the high temperature requirements and has not been demonstrated on any simple cycle or combined cycle combustion turbine. Therefore this control option is not considered technically feasible.

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.

Water or steam injection provides NO_x reductions comparable to that of Dry Low NO_x combustion; however, vendors have reported combustor instability with the introduction of even minute amounts of water. With the resulting incomplete combustion, CO emissions increase dramatically, along with the potential for flameout and unit trip. For these reasons, the vendor recommends against using water injection for continuous NO_x control. In addition, ultra-pure water would be required. Even small quantities of impurities, such as alkali, can damage a gas turbine. Also, large quantities of water are required, typically 1 to 2 pounds of water for each pound of fuel. The cost of treated water can range from 2 to 5 cents per gallon. Based on the concerns described above, this control technology is considered technically feasible but undesirable.

Dry Low NO_X (DLN) combustors utilize a lean fuel pre-mix and staged combustion to create a diffuse flame. The diffuse flame results in reduced combustion zone temperatures thereby lowering the reaction rate that produces thermal NO_x. This combustion strategy focuses on flame temperature for NO_x control, and does not result in increased emission rates of other criteria pollutants due to incomplete combustion. It has the additional benefit that no secondary emissions (such as ammonia slip) are associated with this control strategy. Finally, there are no solid or liquid wastes generated due to the operation of DLN burners.

The various Dry Low NO_x burner designs are relatively new with commercial development occurring in the last 2 to 5 years. However, because their cost-effectiveness in terms of annualized cost per ton NO_x reduced is so favorable, the technology has been rapidly incorporated into new equipment designs. DLN technology is incorporated into the design of the combustion turbine and can achieve NO_x emissions as low as 9 ppmvd for the turbine alone. The combined cycle turbine system with DLN combustion and duct burner firing can achieve NO_x emissions levels of 15 ppmvd corrected to 15% O_2.

Since DLN combustors are a passive control, they require no ancillary equipment and make no contribution to a facility's parasitic power requirements. Additionally, DLN combustors do not create or contribute to a pressure drop and heat loss within the combustion turbine.

Alternatives Analyzed	**Control Costs ($/ton)**	**Technological Feasibility**	**Selection/Rejection**
Thermal $DeNO_x$	--	not feasible	not demonstrated on combustion turbines
SCR w/Dry Low NO_x Burners	--	feasible	**selected**
Dry Low NO_x Combustion	**NA**	**incorporated into turbine design**	
NO_xOUT Process	--	potentially possible	not demonstrated on combustion turbines; ammonia emissions
Water/Steam Injection	--	possible	same NO_x emissions as selected option but CO increases; fuel penalty; water costs

The boiler design will incorporate low NO_x burners for NO_x control, which is common for auxiliary boilers. Due to the intermittent use of this boiler, the use of low NO_x burners is proposed as BACT for NO_x control. The estimated NO_x emissions rate is 0.04 lbs/MMBtu. No adverse environmental or economic impacts are associated with this NO_x control technology.

CO Control Technologies

The combustion turbine and duct burner are subject to NSPS Subparts KKKK and Da, respectively, but these regulations provide no CO emission limits. The following sections assess the control strategies that are potentially feasible for decreasing CO emissions from the facility.

Catalytic Oxidation

The rate of formation of CO during natural gas combustion depends primarily on the efficiency of combustion. The 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 mixing the fuel thoroughly with air.

CO emissions resulting from natural gas combustion can be decreased via catalytic oxidation. The oxidation is carried out by the following overall reaction:

$CO + ½O_2 \rightarrow CO_2$

Several noble metal-enriched catalysts at high temperatures promote this reaction. 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 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.

An economic analysis for the catalytic oxidation of CO emissions based on vendor information estimates the cost at $5,084 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 and duct burners. This determination is consistent with the results of the RBLC database search.

Good Combustion Practices

As shown in the RBLC, the majority of BACT determinations for CO were the use of good combustion practices. Since add-on controls for CO were shown to be economically infeasible, the proposed BACT for CO emissions is the use of good combustion practices. This is consistent with recent Oklahoma BACT determinations.

Energetix proposes a CO BACT limit of 16.38 ppmvd at 15% O_2 for the turbine and duct burner.

PM_{10} Control Technologies

The proposed turbine and duct burner will be subject to NSPS Subpart KKKK and Subpart Da, respectively. There are no specific particulate emission limits established in Subpart KKKK for the combustion turbine, but Subpart Da provides a particulate emission limit of 0.03 lbs/MMBtu for the duct burner.

Properly tuned burners firing natural gas inherently emit low levels of particulate matter (less than 0.007 lbs/MMBtu). The RBLC database indicates that good combustion practices are widely accepted as BACT for turbines and duct burners firing natural gas. Thus, Energetix proposes good combustion practices as BACT for PM_{10} emissions.

Proposed PM_{10} BACT limits for the turbine and duct burner combined are 0.0067 lbs/MMBtu.

BACT Selection

Based on the BACT analysis presented above, the table following summarizes the BACT determinations for the turbine and duct burner. The control technologies selected as BACT are supported by recent entries in the RBLC database. The proposed BACT limits are all below the applicable NSPS limits. In addition, the air quality dispersion modeling analyses performed for this proposed project demonstrates that the criteria pollutant impacts from proposed emissions do not exceed any applicable NAAQS or PSD Increment.

BACT Selection for the Turbine and Duct Burner at 100% Load

Pollutant	BACT Determination	Emission Limits
NO_x	SCR (with duct burner firing) SCR (without duct burner firing)	3.5 ppmvd @ 15% O_2 3.5 ppmvd @ 15% O_2
CO	Good Combustion Practices	16.38 ppmvd @ 15% O_2
PM_{10}	Good Combustion Practices	0.0067 lbs/MMBtu

BACT Evaluation for Auxiliary Boiler

The proposed auxiliary boiler is subject to NSPS Subpart Db. The boiler will be required to maintain a record of fuel usage and use a continuous emissions monitor for NO_x.

Dry low-NO_x (DLN) burners are proposed as NO_x BACT for the auxiliary boiler. Due to the low uncontrolled emission rates of the auxiliary boiler, Energetix proposes good combustion practices as BACT for CO, PM_{10} and VOC emissions from the auxiliary boiler. Energetix also proposes a NO_x emission limit of 0.036 lbs/MMBtu for the low-NO_x burners.

BACT Evaluation for Cooling Tower

Emissions from the cooling tower may include PM_{10} because the water circulating in the tower contains small amounts of dissolved solids (e.g., calcium, magnesium, etc.) that are assumed to crystallize and form airborne particles as the water leaves the cooling tower due to entrainment. AP-42, Section 13.4 estimates of PM_{10} emission factors are extremely conservative because most of the drift droplets will remain in liquid form until they reach the ground due to gravity. Advances in drift eliminator technology have further increased the potential for drift reduction.

Drift eliminators will minimize particulate emissions from the cooling tower and are designated as BACT for each cooling tower in the RBLC database. Energetix proposes drift eliminators as BACT for particulate emissions from the cooling tower, with a PM_{10} BACT limit of 1.54 pounds per million gallons (lbs/MMgals).

B. Air Quality Modeling

Energetix originally submitted an application for this site with two GE 7FA turbines (total 600 MW) and was issued a permit with two GE 7EA turbines (total 308 MW) instead of the one Siemens gas turbine in this application. Full PSD modeling was performed using the larger turbines and the analysis demonstrated that the impacts would not cause or contribute to a violation of the NAAQS or PSD Increment for both Class I and Class II areas. The analysis also showed compliance with Oklahoma's Subchapter 41 Maximum Ambient Air Concentration (MAAC) standards. Therefore, revised air dispersion modeling was not required for the GE 7EA turbines authorized by the previous permit nor the Siemens turbine authorized by this permit. The modeled impacts shown in the following section were proportioned from the original modeling to show the anticipated impact of the two GE 7EA design. The modeling impacts were not updated since the revised stack parameters are roughly equivalent. The GE 7EA stack parameters and emission rates are listed in the "Air Quality Impacts" section.

AIR QUALITY IMPACTS

Prevention of Significant Deterioration (PSD) is a construction permitting program designed to ensure air quality does not degrade beyond the National Ambient Air Quality Standards (NAAQS) or beyond specified incremental amounts above a prescribed baseline level. The PSD rules set forth a review procedure to determine whether a source will cause or contribute to a violation of the NAAQS or maximum increment consumption levels. If a source has the potential to emit a pollutant above the PSD significance levels, then they trigger this review process. EPA has provided modeling significance levels for the PSD review process to determine whether a source will cause or contribute to a violation of the NAAQS or consume increment. 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 analyses are required for the Class II area.

Modeling conducted by the applicant and reviewed by the DEQ demonstrated that emissions from the facility will not exceed the PSD modeling significance levels for CO. However, a full impact analysis was required for NO_2 and PM_{10}. Emissions of SO_2 did not exceed the PSD significant emission rates and therefore an air quality analysis was not required.

Modeling

The air quality modeling analyses employed USEPA's Industrial Source Complex Short Term Version 3 (ISCST3) model (USEPA, 1995a). The ISCST3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash (40 CFR 40465-40474). However the current version of ISCST3 is not capable of determining cavity concentrations. Therefore, the ISC-Prime model was used to estimate ground-level concentrations identified in the ISCST3 model runs as cavity region receptors.

The ISCST3 model (Version 00101) was used for all pollutants. The regulatory default option was selected such that USEPA guideline requirements were met.

VOC is not limited directly by NAAQS. Rather, it is regulated as an ozone precursor. EPA developed a method for predicting ozone concentrations based on VOC and NO_x concentrations in an area. The ambient impacts analysis utilized these tables from "VOC/NO_x Point Source Screening Tables" (Richard Scheffe, OAQPS, September 1988). The Scheffe tables utilize increases in NO_x and VOC emissions to predict increases in ozone concentrations.

The stack height regulations promulgated by USEPA on July 8, 1985 (50 CFR 27892), established a stack height limitation to assure that stack height increases and other plume dispersion techniques would not be used in lieu of constant emission controls. The regulations specify that Good Engineering Practice (GEP) stack height is the maximum creditable stack height that a source may use in establishing its applicable State Implementation Plan (SIP) emission limitation. For stacks uninfluenced by terrain features, the determination of a GEP stack height for a source is based on the following empirical equation:

$$H_g = H + 1.5L_b$$

where:

H_g = GEP stack height;
H = Height of the controlling structure on which the source is located, or nearby structure; and
L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. The area in which a nearby structure can have a significant influence on a source is limited to five times the lesser dimension (height or width) of that structure, or within 0.5 mile (0.8 km) of the source, whichever is less. The methods for determining GEP stack height for various building configurations have been described in USEPA's technical support document (USEPA, 1985).

Since the heights of exhaust stacks at the proposed power plant are less than respective GEP stack heights, a dispersion model to account for aerodynamic plume downwash was necessary in performing the air quality impact analyses.

Since downwash is a function of projected building width and height, it is necessary to account for the changes in building projection as they relate to changes in wind direction. Once these projected dimensions are determined, they can be used as input to the ISC3 model.

In October 1993 USEPA released the Building Profile Input Program (BPIP) to determine wind direction-dependent building dimensions. The BPIP algorithms as described in the User's Guide (USEPA, 1993), have been incorporated into the commercially available BREEZEWAKE program. The BREEZEWAKE program was used to determine the wind direction-dependent building dimensions for input to the ISC3 model.

The BPIP program builds a mathematical representation of each building to determine projected building dimensions and its potential zone of influence. These calculations are performed for 36 different wind directions (at 10 degree intervals). If the BPIP program determines that a source is under the influence of several potential building wakes, the structure or combination of structures that have the greatest influence (h_b + 1.5 l_b) are selected for input to the ISCST3 model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-case building dimensions for that direction yield a wake region height less than the source's physical stack height, building parameters are set equal to zero for that wind direction. For this case, wake effect algorithms are not exercised when the model is run. The building wake criteria influence zone is 5 l_b downwind, 2 l_b upwind, and 0.5 l_b crosswind. These criteria are based on recommendations by USEPA. The input to the BREEZEWAKE preprocessing program consisted of proposed power plant exhaust stacks (two CTs and an auxiliary boiler) and building dimensions.

The meteorological data used in the dispersion modeling analyses consisted of five years (1986-1988, 1990, 1991) of hourly surface observations from the Wichita Falls, Texas, National Weather Service Station (Station number 13966) and coincident mixing heights (1986-1988) from Oklahoma City, NWS 13967 and (1990 and 1991) from Norman, Oklahoma, NWS 3948. Surface observations consist of hourly measurements of wind direction, wind speed, temperature, and estimates of ceiling height and cloud cover. The upper air station provides a daily morning and afternoon mixing height value as determined from the twice-daily radiosonde measurements. Based on NWS records, the anemometer height at the Wichita Falls station during this period was 6.4 meters. Prior to use in the modeling analysis, the meteorological data sets were scanned for missing data. The procedures outlined in the USEPA document, “Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models,” were used to fill gaps of information for single missing days. For larger periods of two or more missing days, seasonal averages were used to fill in the missing periods. The USEPA developed rural and urban interpolation methods to account for the effects of the surrounding area on development of the mixing layer boundary. The rural scheme was used to determine hourly mixing heights representative of the area in the vicinity of the proposed power plant.

The urban/rural classification is used to determine which dispersion parameter to use in the model. Determination of the applicability of urban or rural dispersion is based upon land use or population density. The land use method is preferred. For the land use method the source is circumscribed by a three kilometer radius circle, and uses within that radius analyzed to determine whether heavy and light industrial, commercial, and common and compact residential, comprise greater than 50 percent of the defined area. If so, then urban dispersion coefficients should be used. The land use in the area of the proposed facility is not comprised of greater than 50 percent of the above land use types.

The receptor grid for the ISCST3 dispersion model was designed to identify the maximum air quality impact due to the proposed power plant. Several different rectangular grids made up of discrete receptors were used in the ISCST3 modeling analysis. The receptor grids are made up of 100-meter spaced fine receptors, 500-meter spaced medium receptors and 1,000-meter spaced coarse receptors. The grids were defined as follows:

- A “fenceline grid” consisting of evenly-spaced receptors 100 meters apart placed along the proposed facility fenceline.
- A “fine grid” containing 100-meter spaced receptors extending approximately 1.0 km from the fenceline exclusive of the receptors within the proposed facility fenceline.
- A “medium grid” containing 500-meter spaced receptors extending approximately 5 km from the fenceline exclusive of receptors in the fine grid.
- A “coarse grid” containing 1,000-meter spaced receptors extending approximately 10 km from the fenceline exclusive of receptors in the fine and medium grid.
- A “Class I area medium grid” containing 500-meter spaced receptors covering the entire Wichita Mountains National Wildlife Area.
- Three “Class I area medium-tight grids” consisting of 100-meter spaced receptors centered on the highest receptor concentration on the Class I area medium grid.

All receptors were modeled with actual terrain based on the proposed plant location. The terrain data was taken from United States Geologic Society (USGS) and Digital Elevation Model (DEM) data. This data was obtained in the USGS native format. The DEM files were then used to derive the terrain elevation data with the BREEZE software terrain import function. An interpolation technique is used to match terrain heights to each individual receptor. The “highest” interpolation technique was chosen. It selects the highest of the four terrain elevations encompassing each object. This generates the most conservative estimates for grid spacing greater than 60 meters. All building, source location, and terrain data were based on the NAD27 datum.

The stack emission rates and parameters needed for the proposed power plant included the two CTs, the exhaust stacks of the auxiliary boiler and the cooling water tower. The cooling water towers contribute a minimal amount of particulate matter emissions. The proposed CTs can operate at various loads. The emission rates used for the analysis were the maximum estimated emission rates for each pollutant at maximum load.

Stack Parameters							
Source	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**m**	**°K**	**m/sec**	**m**
Turbine No.1	545388	3828161	368	45.72	353.65	18.04	4.57
Turbine No.2	545386	3828111	368	45.72	353.65	18.04	4.57
Auxiliary Boiler	545379	3828239	368	18.29	427.59	15.99	1.83
CW Tower	545357	3828363	368	15.24	313.15	6.44	11.06

Emission Rates			
Source	**NO_2 [1]**	**CO**	**PM_{10}**
	lbs/hr	**lbs/hr**	**lbs/hr**
Turbine No.1 (2)	14.04	103.42	20.30
Turbine No.2 (2)	14.04	103.42	20.30
Auxiliary Boiler	9.72	22.30	2.48
CW Tower (3)	---	---	4.29

(1) The Ambient Ratio Method assumes a conversion of 75% of NO_X to NO_2 and was used to calculate the emission rate.
(2) Includes the CT and the duct burner.
(3) The PM_{10} emission rate is the total for the cooling tower (8 cells).

The modeling results for the significance analysis are shown following. The highest first high concentrations over the five-year period were used to demonstrate compliance with the modeling significance levels for each pollutant.

Class II Significance Level Comparisons				
Pollutant	**Averaging Period**	**Maximum Concentrations**	**Modeling Significance Level**	**Monitoring de minimis Concentration**
		(μg/m³)	**(μg/m³)**	**(μg/m³)**
NO_2	Annual	2.85	1	14
CO	8-hour	243.055	500	575
	1-hour	671.719	2000	
PM_{10}	Annual	1.714	1	
	24-hour	9.752	5	10

The modeling indicates facility emissions will result in ambient concentrations above the significance levels in which an area of impact is defined for NO_2 and PM_{10}. Therefore, additional modeling for PSD increment or NAAQS compliance is required.

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 for NO_2 and PM_{10}. VOC emissions are greater than the 100 TPY monitoring significance level. The Lawton ozone monitor, ID 400310647-1, records ozone data and as recently as 1998 recorded NO_2 data. This monitor is located approximately 8.4 miles away from the proposed Lawton Energy Cogen and provides representative background data for ozone in lieu of pre-construction monitoring. The Lawton PM_{10} monitor, ID 400310640-1, recorded PM_{10} data as recently as 1997. This monitor is located approximately 8.4 miles away from the proposed Lawton Energy Cogen and provides representative background data for PM_{10} for the NAAQS analysis. There have been no monitored exceedances of the NAAQS for PM_{10}, NO_2, or the one-hour ozone standard in Comanche County.

Monitoring Data Summary	
NO_2 Annual Mean (ID 400310647-1)[1]	16.9 μg/m^3
PM_{10} Annual Mean (ID 400310640-1)[2]	26.2 μg/m^3
PM_{10} Second High (ID 400310640-1)[2]	63.0 μg/m^3
Ozone Fourth High (ID 400310647-1)[3]	0.094 ppm

(1) The most recent complete year of data was 1998.
(2) The most recent complete year of data was 1997.
(3) The fourth high concentration over a three-year period, 1998-2000, is the design value for the ozone monitor.

NAAQS Analysis

The emissions of NO_X and PM_{10} were determined to have significant impacts. All other pollutants were shown to have modeled impacts below significance levels. Based on this determination, a modeling analysis to determine the effect of the proposed emissions on the NAAQS was made.

The full impact analysis to demonstrate compliance with the NAAQS expanded the significance analysis to include existing sources as well as new significant sources within a 50-km radius of the area of impact, AOI, determined in the significance analysis. The AOI is defined as the area circumscribed by a radius extending to the farthest receptor, which exceeds the modeling significance levels. This radius is the radius of impact, ROI.

The ROI for NO_2 was 1.53 kilometers from the center of the facility. The ROI for the annual PM_{10} standard was 0.68 kilometers. The ROI for the 24-hour PM_{10} standard was 1.72 kilometers. The AOI plus 50 kilometers extended 2-3 kilometers into Texas.

In order to eliminate sources with minimal affect on the area of impact, a screening procedure known as the “20D Rule” was applied to the sources on the emission inventory from Oklahoma. This is a screening procedure designed to reduce the number of insignificant modeled sources. The rule is applied by multiplying the distance from the sources (in kilometers) by 20. If the result is greater than the emission rate (in tons per year), the source is eliminated. If the result is less than the emission rate, the source is included in the NAAQS analysis. The following table lists the background sources and parameters used in the modeling for the NAAQS analysis.

NO_2 NAAQS Background Sources								
Facility	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Emission Rate**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**lbs/hr**	**m**	**K**	**m/s**	**m**
PSO - Comanche Power Station	561983	3822435	339	759	16.15	452.59	46.25	3.11
PSO - Comanche Power Station	561983	3822435	339	759	16.15	454.82	46.25	3.11
Smith Energy GT_North	563070	3830005	357	130	45	369.26	18.11	5.79
Smith Energy GT_South	563143	3830006	358	130	45	369.26	18.11	5.79
Smith Energy Diesel	563172	3829953	359	7.75	13.72	783.15	18.9	0.2
Smith Energy AuxBLR	563114	3830007	357	9.40	16.76	449.82	9.14	0.61
Great Plains Energy Facility -Turbine 1	562102	3821030	338	55.33	45.72	354.54	15.85	5.79
Great Plains Energy Facility -Turbine 2	562145	3821030	338	55.33	45.72	354.54	15.85	5.79
Great Plains Energy Facility - Aux Boiler	562030	3821066	338	1.31	24.38	422.04	9.14	0.61
Bar-S Foods - Smokehouse Stacks	545076	3829003	374.6	1.40	3.35	366.48	16.17	0.61
Bar-S Foods - Boiler Stacks	545076	3828973	374.6	5.51	3.35	477.59	3.23	0.61

PM_{10} NAAQS Background Sources								
Facility	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Emission Rate**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**lbs/hr**	**m**	**K**	**m/s**	**m**
PSO - Comanche Power Station	561983	3822435	339	88.41	16.15	452.59	46.25	3.11
PSO - Comanche Power Station	561983	3822435	339	88.41	16.15	454.82	46.25	3.11
Smith Energy GT_North	563070	3830005	357	21.98	45	369.26	18.11	5.79
Smith Energy GT_South	563143	3830006	358	21.98	45	369.26	18.11	5.79
Smith Energy CT_1	563225	3830069	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_2	563232	3830054	361	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_3	563239	3830039	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_4	563246	3830024	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_5	563253	3830009	361	0.59	13.72	298.15	8.84	8.53

PM10 NAAQS Background Sources								
Facility	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Emission Rate**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**lbs/hr**	**m**	**K**	**m/s**	**m**
Smith Energy CT_6	563260	3829994	361	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_7	563267	3829978	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_8	563273	3829963	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_9	563280	3829948	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_10	563287	3829933	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_11	563294	3829918	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_12	563301	3829903	360	0.59	13.72	298.15	8.84	8.53
Smith Energy Diesel	563172	3829953	359	0.55	13.72	783.15	18.9	0.2
Smith Energy AuxBLR	563114	3830007	357	0.72	16.76	449.82	9.14	0.61
Great Plains Energy Facility -Turbine 1	562102	3821030	338	32.76	45.72	354.54	15.85	5.79
Great Plains Energy Facility -Turbine 2	562145	3821030	338	32.76	45.72	354.54	15.85	5.79
Great Plains Energy Facility - Aux Boiler	562030	3821066	338	0.26	24.38	422.04	9.14	0.61
Great Plains Energy Facility - CT Cell #1	561936	3820914	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #2	561936	3820931	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #3	561937	3820948	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #4	561937	3820965	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #5	561937	3820982	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #6	561936	3820998	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #7	561937	3821015	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #8	561937	3821032	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #9	561937	3821049	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #10	561937	3821066	338	0.15	19.81	314.82	9.56	10.06

The NO_2 annual, PM_{10} annual, and PM_{10} 24-hour high 1st high were analyzed for compliance with the NAAQS. The applicant has demonstrated compliance through the application of the NO_2/NO_X ratio of 0.75 applied to the emission rate of NO_X as is allowed in the "Guideline on Air Quality Models." Further guidance from EPA allows the use of the high 4th high over a period of five years or the sixth high over a five year period to demonstrate compliance with the PM_{10} standards. The use of the high first high is considered to be conservative.

NAAQS Analysis for NO_2 Annual and PM_{10} 24-hour and Annual				
Pollutant	**Refined Model Maximum**	**Monitored Background**	**Refined + Background**	**NAAQS Limit**
	($\mu g/m^3$)	**($\mu g/m^3$)**	**($\mu g/m^3$)**	**($\mu g/m^3$)**
NO_2 Annual	21.97	16.9	38.87	100
PM_{10} Annual	1.856	26.2	28.056	50
PM_{10} 24-hour [1]	9.75	63.0	72.75	150

[1] The high 1st high modeled concentration for the PM_{10} 24-hour standard was used to demonstrate compliance with the NAAQS.

An ozone analysis was carried out based on the method in "VOC/NO_X Point Source Screening Tables" created by Richard Scheffe from the results of reactive plume modeling of the emissions of volatile organic compounds (VOC) and NO_X. The impact of all proposed VOC and NO_X emissions associated with the project is estimated at 0.0026 ppm. Based on a fourth high (design) monitored concentration for the years 1998, 1999 and 2000 of 0.094 ppm from the Lawton Monitor (400310647-1), the projected impact at 0.0966 will not exceed the ozone NAAQS of 0.12 ppm.

Increment Consumption

The PSD increment analysis compares all increment consuming emission increases in the area of impact since the baseline date against the available increment. The amount of available increment is based on other sources constructed within the area of impact since the baseline date. The PM_{10} minor source baseline date was triggered for Comanche County on June 13, 2000, for PM_{10} and NO_2. Minor increases and decreases at existing major facilities may impact the increment consumption prior to the minor source baseline date. ODEQ under guidance from EPA allows the use of the "20D Rule" for increment consumption evaluations as well as NAAQS evaluations.

The following background sources were modeled at permitted rather than actual emissions to demonstrate compliance with the increment consumption levels.

NO_2 Increment Consumers								
Facility	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Emission Rate**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**lbs/hr**	**M**	**K**	**m/s**	**m**
Smith Energy GT_North	563070	3830005	357	130	45	369.26	18.11	5.79
Smith Energy GT_South	563143	3830006	358	130	45	369.26	18.11	5.79
Smith Energy Diesel	563172	3829953	359	7.75	13.72	783.15	18.9	0.2
Smith Energy AuxBLR	563114	3830007	357	9.40	16.76	449.82	9.14	0.61
Great Plains Energy Facility - Turbine 1	562102	3821030	338	55.33	45.72	354.54	15.85	5.79
Great Plains Energy Facility - Turbine 2	562145	3821030	338	55.33	45.72	354.54	15.85	5.79
Great Plains Energy Facility - Aux Boiler	562030	3821066	338	1.31	24.38	422.04	9.14	0.61

PM_{10} Increment Consumers								
Facility	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Emission Rate**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**lbs/hr**	**m**	**K**	**m/s**	**m**
Smith Energy GT_North	563070	3830005	357	21.98	45	369.26	18.11	5.79
Smith Energy GT_South	563143	3830006	358	21.98	45	369.26	18.11	5.79
Smith Energy CT_1	563225	3830069	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_2	563232	3830054	361	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_3	563239	3830039	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_4	563246	3830024	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_5	563253	3830009	361	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_6	563260	3829994	361	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_7	563267	3829978	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_8	563273	3829963	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_9	563280	3829948	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_10	563287	3829933	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_11	563294	3829918	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_12	563301	3829903	360	0.59	13.72	298.15	8.84	8.53

PM_{10} Increment Consumers								
Facility	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Emission Rate**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**lbs/hr**	**m**	**K**	**m/s**	**m**
Smith Energy Diesel	563172	3829953	359	0.55	13.72	783.15	18.9	0.2
Smith Energy AuxBLR	563114	3830007	357	0.72	16.76	449.82	9.14	0.61
Great Plains Energy Facility -Turbine 1	562102	3821030	338	32.76	45.72	354.54	15.85	5.79
Great Plains Energy Facility -Turbine 2	562145	3821030	338	32.76	45.72	354.54	15.85	5.79
Great Plains Energy Facility - Aux Boiler	562030	3821066	338	0.26	24.38	422.04	9.14	0.61
Great Plains Energy Facility - CT Cell #1	561936	3820914	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #2	561936	3820931	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #3	561937	3820948	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #4	561937	3820965	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #5	561937	3820982	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #6	561936	3820998	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #7	561937	3821015	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #8	561937	3821032	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #9	561937	3821049	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #10	561937	3821066	338	0.15	19.81	314.82	9.56	10.06

The following table presents the results of the increment analysis. The applicant has demonstrated compliance.

Class II Increment Consumption Analysis			
Pollutant	**Averaging Period**	**Maximum Concentrations ($\mu g/m^3$)**	**Max. Allowable Increment Consumption ($\mu g/m^3$)**
NO_2	Annual	2.934	25
PM_{10}	Annual	1.749	17
	24-hour [1]	9.752	30

[1] The high 1st high modeled concentration for the PM_{10} 24-hour standard was used to demonstrate compliance with the Increment.

Additional Impacts Analyses

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. Approximately 30 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. The number of new permanent jobs created by the project is expected to be approximately 30. To the extent possible, these jobs will be filled from the local labor pool. Accordingly, negligible new growth is anticipated as a result of the new facility.

Soils and Vegetation

The following discussion will review the projects potential to impact its agricultural surroundings based on the facility's allowable emission rates and resulting ground level concentrations of NO_2, VOC, CO, and PM_{10}.

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 adverse effects of airborne effluents. This protection extends to agricultural soil. The modeling conducted, which demonstrated compliance with the Primary NAAQS, simultaneously demonstrated compliance with the Secondary NAAQS because the Secondary NAAQS are higher or equal to the Primary NAAQS. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated due to the proposed power plant.

VOCs are regulated by the U.S. EPA as precursors to tropospheric ozone. Elevated ground-level ozone concentrations can damage plant life and reduce crop production. VOCs interfere with the ability of plants to produce and store food, making them more susceptible to disease, insects, other pollutants, and harsh weather. No significant impact on soil and vegetation due to VOC emissions is anticipated due to the proposed power plant.

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. As demonstrated, the maximum predicted CO pollutant concentrations from the proposed power plant are below the NAAQS. Therefore, no significant adverse impact on soil and vegetation due to CO emissions is anticipated due to the proposed power plant.

PM can be carried over long distances by the wind and settle on the ground. The effects of this deposition can 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. Therefore, no significant impact on soil and vegetation due to PM_{10} emissions is anticipated due to the proposed power plant.

Visibility Impairment

The project is not expected to produce any perceptible visibility impacts in the vicinity of the plant. EPA computer software for visibility impacts analyses, intended to predict distant impacts, terminates prematurely when attempts are made to determine close-in impacts. It is concluded that there will be minimal impairment of visibility resulting from the facility's emissions. Given the limitation of 20% opacity of emissions, and a reasonable expectation that normal operation will result in 0% opacity, no local visibility impairment is anticipated.

Class I Area Impact Analysis

The following (in italics) relates to modeling performed for this application by Eric Milligan of DEQ Air Quality.

Three of the four major sources that were modeled for increment consumption for the original permit were not constructed. The applications for the Smith Energy and Great Plains facilities were both withdrawn and even though the permit for the Duke Energy facility was issued it has expired. The Western Farmers Electric Cooperative GENCO facility was constructed and was included in the review of the modeling conducted to determine compliance with the Class I increment at the Wichita Mountains Wildlife Reserve (WMWR). Also included were other existing sources that have consumed increment located within 100 km of the WMWR, which were left out of the previous review, and two turbines that are planned to be constructed at the PSO Southwest facility, for which a PSD construction permit was recently submitted.

The sources were modeled using ISC3 and AERMOD. It was determined that the maximum impacts were calculated with ISC3 and that those impacts were below the impacts previously modeled and were also below the maximum allowable Class I NO_2 increment consumption of 2.5 $\mu g/m^3$.

YEAR	*AERMOD*	*ISC3*
'86	*0.07*	*0.19*
'87	*0.07*	*0.19*
'88	*0.06*	*0.17*
'90	*0.05*	*0.14*
'91	*0.07*	*0.18*

The remaining discussion down to Section V is the original Class I area analysis.

A further requirement of PSD includes the special protection of air quality and air quality related values (AQRV) at potentially affected nearby Class I areas. Assessment of the potential impact to visibility (regional haze analysis) is required if the source is located within 100 km of a Class I area. An evaluation may be requested if the source is within 200 km of a Class I area. The facility is approximately 14.4 km south of the Wichita Mountains National Wildlife Refuge (Wichita Mountains NWR) and approximately 19.3 kilometers from the farthest boundary of the Class I area. Due to the proximity of the source to the Class I area, the source was required to perform significance analysis for Class I increment consumption. Maximum impacts were compared to the modeling significance levels for the Class I area.

Class I Significance Level Comparisons			
Pollutant	**Averaging Period**	**Maximum Concs.**	**Modeling Significance Levels**
		($\mu g/m^3$)	**($\mu g/m^3$)**
NO_2	Annual	0.138	0.1
PM_{10}	24-hour	1.100	0.3
PM_{10}	Annual	0.145	0.2

Results of the significance analysis indicate that concentrations of NO_2 exceed the annual averaging MSL, and PM_{10} exceeds the 24-hour MSL; therefore, a full impact analysis was required for each pollutant at all receptors within the Class I area. No additional NAAQS analysis for Class I areas is required beyond the analysis submitted.

The PSD increment analysis compares all increment consuming emission increases in the area of impact since the baseline date against the available increment. The amount of available increment is based on other sources constructed within the area of impact since the baseline date. Though the source that set the baseline date for Comanche County did not obtain a permit nor evaluate its impact on increment consumption in the Class I area, the baseline date for increment consumption in the Class I area is the same as that for the Class II area in Comanche County. The PM_{10} minor source baseline date was triggered for Comanche County on June 13, 2000, for PM_{10} and NO_2. Minor increases and decreases at existing major facilities may impact the increment consumption prior to the minor source baseline date. ODEQ under guidance from EPA allows the use of the "20D Rule" for increment consumption evaluations as well as NAAQS evaluations. However the 20D Rule is not appropriate for the Class I increments. Therefore, all PSD sources on or after the baseline date within the ROI plus 50 kilometers were included in the analysis.

The maximum impact area extends 33.44 kilometers from the facility for NO_2 and 37.67 kilometers from the facility for PM_{10} (24-hour).

The following background sources were modeled at permitted rather than actual emissions to demonstrate compliance with the increment consumption levels.

Class I NO_2 Increment Consumers								
Facility	UTM Easting	UTM Northing	Base Elevation	Emission Rate	Stack Ht.	Stack Temp.	Stack Vel.	Stack Dia.
	m	m	m	lbs/hr	m	K	m/s	m
Smith Energy GT_North	563070	3830005	357	130	45	369.26	18.11	5.79
Smith Energy GT_South	563143	3830006	358	130	45	369.26	18.11	5.79
Smith Energy Diesel	563172	3829953	359	7.75	13.72	783.15	18.9	0.2
Smith Energy AuxBLR	563114	3830007	357	9.40	16.76	449.82	9.14	0.61
Great Plains Energy Facility - Turbine 1	562102	3821030	338	55.33	45.72	354.54	15.85	5.79
Great Plains Energy Facility - Turbine 2	562145	3821030	338	55.33	45.72	354.54	15.85	5.79
Great Plains Energy Facility - Aux Boiler	562030	3821066	338	1.31	24.38	422.04	9.14	0.61
Duke Energy - Turb1	595640	3810102	319	45.65	49.07	366.5	21.15	5.49
Duke Energy - Turb2	595598	3810102	319	45.65	49.07	366.5	21.15	5.49
Duke Energy - AuxB	595698	3810094	319	2.71	18.29	476.5	12.19	0.81
Duke Energy - Egen	595668	3810096	319	0.12	6.1	914.8	66.2	0.2
Duke Energy - FWPump	595647	3810191	319	0.07	4.27	804.3	24.63	0.15
WFEC Genco - Peaking Turbine #1	570486	3882418	360	13.64	13.72	694.26	42.97	2.74
WFEC Genco - Peaking Turbine #2	570486	3882396	360	13.64	13.72	694.26	42.97	2.74

Class I PM_{10} Increment Consumers								
Facility	UTM Easting	UTM Northing	Base Elevation	Emission Rate	Stack Ht.	Stack Temp.	Stack Vel.	Stack Dia.
	m	m	m	lbs/hr	m	K	m/s	m
Smith Energy GT_North	563070	3830005	357	21.98	45	369.26	18.11	5.79
Smith Energy GT_South	563143	3830006	358	21.98	45	369.26	18.11	5.79
Smith Energy CT_1	563225	3830069	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_2	563232	3830054	361	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_3	563239	3830039	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_4	563246	3830024	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_5	563253	3830009	361	0.59	13.72	298.15	8.84	8.53

Class I PM_{10} Increment Consumers								
Facility	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Emission Rate**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**lbs/hr**	**m**	**K**	**m/s**	**m**
Smith Energy CT_6	563260	3829994	361	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_7	563267	3829978	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_8	563273	3829963	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_9	563280	3829948	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_10	563287	3829933	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_11	563294	3829918	360	0.59	13.72	298.15	8.84	8.53
Smith Energy CT_12	563301	3829903	360	0.59	13.72	298.15	8.84	8.53
Smith Energy Diesel	563172	3829953	359	0.55	13.72	783.15	18.9	0.2
Smith Energy AuxBLR	563114	3830007	357	0.72	16.76	449.82	9.14	0.61
Great Plains Energy Facility - Turbine 1	562102	3821030	338	32.76	45.72	354.54	15.85	5.79
Great Plains Energy Facility - Turbine 2	562145	3821030	338	32.76	45.72	354.54	15.85	5.79
Great Plains Energy Facility - Aux Boiler	562030	3821066	338	0.26	24.38	422.04	9.14	0.61
Great Plains Energy Facility - CT Cell #1	561936	3820914	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #2	561936	3820931	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #3	561937	3820948	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #4	561937	3820965	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #5	561937	3820982	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #6	561936	3820998	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #7	561937	3821015	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #8	561937	3821032	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #9	561937	3821049	338	0.15	19.81	314.82	9.56	10.06
Great Plains Energy Facility - CT Cell #10	561937	3821066	338	0.15	19.81	314.82	9.56	10.06
Duke Energy - Turb1	595640	3810102	319	34.00	49.07	366.5	21.15	5.49
Duke Energy - Turb2	595598	3810102	319	34.00	49.07	366.5	21.15	5.49
Duke Energy - AuxB	595698	3810094	319	0.23	18.29	476.5	12.19	0.81

Class I PM_{10} Increment Consumers								
Facility	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Emission Rate**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**lbs/hr**	**m**	**K**	**m/s**	**m**
Duke Energy ctv1	595739	3810137	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv2	595739	3810121	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv3	595739	3810106	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv4	595740	3810090	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv5	595740	3810075	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv6	595740	3810059	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv7	595740	3810043	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv8	595740	3810028	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv9	595740	3810012	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv10	595741	3809996	319	0.115	14.33	293.2	14.33	12.48
Duke Energy ctv11	595552	3810104	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv12	595557	3810104	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv13	595561	3810104	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv14	595566	3810104	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv15	595552	3810087	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv16	595556	3810087	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv17	595560	3810087	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv18	595565	3810087	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv19	595552	3810070	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv20	595557	3810070	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv21	595561	3810070	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv22	595565	3810070	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv23	595552	3810053	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv24	595556	3810053	319	0.02	13.72	293.2	14.33	3.67

Class I PM_{10} Increment Consumers								
Facility	**UTM Easting**	**UTM Northing**	**Base Elevation**	**Emission Rate**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	m	**m**	**m**	**lbs/hr**	**m**	**K**	**m/s**	**m**
Duke Energy ctv25	595561	3810053	319	0.02	13.72	293.2	14.33	3.67
Duke Energy ctv26	595565	3810053	319	0.02	13.72	293.2	14.33	3.67
Duke Energy - Egen	595668	3810096	319	0.006	6.1	914.8	66.2	0.2
Duke Energy - FWPump	595647	3810191	319	0.005	4.27	804.3	24.63	0.15
WFEC Genco - Peaking Turbine #1	570486	3882418	360	1.370	13.72	694.26	42.97	2.74
WFEC Genco - Peaking Turbine #2	570486	3882396	360	1.370	13.72	694.26	42.97	2.74

The following table presents the results of the increment analysis. The applicant has demonstrated compliance.

Class I Increment Consumption Analysis			
Pollutant	**Averaging Period**	**Maximum Concentrations ($\mu g/m^3$)**	**Max. Allowable Increment Consumption ($\mu g/m^3$)**
NO_2	Annual	0.602	2.5
PM_{10}	24-hour [1]	2.839	8

[1] The high 1st high modeled concentration for the PM_{10} 24-hour standard was used to demonstrate compliance with the Increment.

A visibility impairment analysis was required to demonstrate that emissions from the Lawton Energy Cogen Facility will not have an adverse impact on visibility in the vicinity of Wichita Mountains NWR. The visibility analysis was conducted on the initial 600 MW configuration of the facility. Because the emissions of all pollutants of concern were reduced for the final 308 MW configuration, the analysis was not repeated. The visibility analysis conducted should be considered to be extremely conservative.

The U.S. EPA's "Workbook for Plume Visual Impact Screening and Analysis" provides guidance for conducting a visibility impairment analysis through the use of VISCREEN, a plume visibility impact model. VISCREEN allows for two levels of visibility impact screening. Level 1 screening involves a series of conservative calculations designed to identify those emissions that have minimal potential for adversely affecting visibility. If visibility impairments are indicated, a Level 2 analysis, which allows for modification of default parameters including meteorological data, is performed. Both Level 1 and Level 2 analyses were performed for this study.

For the purposes of VISCREEN modeling, a PM_{10} emission rate of 313.31 TPY and a NO_X emission rate of 710.03 TPY were used. The default values of "0" lbs/hr was chosen for primary NO_2, soot, and primary sulfate emissions.

Based on data from the Workbook for Plume Visual Impact Screening and Analysis, a visual background range value of 40 km was selected.

The distance from the Lawton Energy Cogen Facility to the closest boundary of the Wichita Mountains NWR was calculated to be 14.4 km and to the farthest boundary of the refuge was 19.3 km. The lower bound of the cardinal wind direction sector (containing the observer) was determined to be 337.5° and the upper bound 360°.

The VISCREEN model results following are expressed in terms of perceptibility (Delta E) and contrast. The default criteria for perceptibility and contrast were used.

Level I VISCREEN Results								
Background	**Theta**	**Azimuth**	**Distance**	**Alpha**	**Delta E**		**Contrast**	
	Degrees	**Degrees**	**Km**	**Degrees**	**Critical**	**Plume**	**Critical**	**Plume**
Sky	10	125	19.3	28	2.00	6.555	0.05	0.041
Sky	140	125	19.3	28	2.00	2.359	0.05	-0.051
Terrain	10	84	14.4	84	2.00	6.936	0.05	0.065
Terrain	140	84	14.4	84	2.00	1.038	0.05	0.029

The input parameters for the Level 2 VISCREEN analysis are the same as those used in the Level 1 analysis, except that the default meteorological conditions of F-stability and 1 m/s wind speed are not used. Rather, the Level 2 analysis is performed using actual meteorological data. These data are a combination of data obtained from the Oklahoma City upper air and Wichita Falls surface meteorological stations. Data for the years 1986-1988 and 1990-1991 were used.

The year with the highest percentage of hourly flow vectors within the cardinal flow vector sector containing the observer location was chosen to determine the representative worst-case meteorological conditions. The 1990 year of meteorological data corresponded to the highest frequency of occurrence of flow vectors (16.9%).

Following U.S. EPA guidance, a joint frequency distribution of occurrence of wind speed, flow vector, stability class, and time of day were prepared. Periods of meteorological conditions for which the flow vector falls within the cardinal flow vector sector that contains the observer are chosen to determine the joint frequency distribution of meteorological categories. The meteorological categories are then ranked in order of increasing dispersion capability.

The flow vector for each hour of observed meteorological data are tested to see if occurrence for the appropriate meteorological category is incremented. Upon processing each hour of data, a table of frequencies of occurrence of each meteorological category for each of four time periods is produced.

Cumulative Frequency Analysis								
Stability	**Transport Time**	**Wind Speed**	**Frequency of Occurrence For Given Time of Day**				**Frequency**	**Cumulative Frequency**
	hrs	**m/s**	**%**				**%**	**%**
			0-6	7-12	13-18	19-24		
F	4.0	1.0	0.24	0.02	0.00	0.06	0.24	0.24
F	2.0	2.0	0.39	0.01	0.00	0.49	0.49	0.73
E	4.0	1.0	0.00	0.02	0.00	0.02	0.02	0.75
F	1.3	3.0	0.35	0.00	0.00	0.33	0.35	1.11

The meteorological category selected for use in VISCREEN is that which causes the cumulative frequency of occurrence to exceed one percent. This condition is chosen to be indicative of worst-day plume visual impacts. The meteorological conditions of F stability and a wind speed of 3 m/s were used.

The results of the Level 2 VISCREEN analysis are summarized in the following table.

Level 2 VISCREEN Results								
Background	**Theta**	**Azimuth**	**Distance**	**Alpha**	**Delta E**		**Contrast**	
	Degrees	**Degrees**	**Km**	**Degrees**	**Critical**	**Plume**	**Critical**	**Plume**
Sky	10	140	19.3	28	2.00	2.354	0.05	0.015
Sky	140	140	19.3	28	2.00	0.865	0.05	-0.018
Terrain	10	84	14.4	84	2.00	2.513	0.05	0.023
Terrain	140	84	14.4	84	2.00	0.352	0.05	0.010

The rows in the table for which Theta is equal to 10 degrees can be disregarded since these are associated with an unrealistic geometry. The 10-degree scenario is only possible for views to the east (in the mornings), south (for high latitudes and winter periods), and west (in the evenings). Since the view is toward the north in this case, the 10-degree forward scatter scenario is not geometrically realistic. Therefore, no further analysis was required.

SECTION V. OKLAHOMA AIR POLLUTION CONTROL RULES

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

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-4 (New Source Performance Standards) [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, Emission Inventory, And Annual Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. Since this is construction for a new facility, no emission inventories or annual fees have previously been paid.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

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

Emission limitations have been established for each emission unit based on information from the permit application. An administratively complete operating permit application will be filed with the DEQ within 180 days following commencement of operation.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day following the malfunction or release. Further written notice containing specific details of the incident shall be submitted within ten (10) business days.

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

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies a particulate matter (PM) emission limitation of 0.6 lbs/MMBtu from new or existing fuel-burning units with a rated heat input of 10 MMBtu/hr or less. For fuel-burning units with rated heat input greater than 10 MMBtu/hr, this subchapter specifies a PM emission limitation based upon the heat input of the equipment. Subchapter 19 specifies allowable particulate matter emissions of 0.152 lbs/MMBtu based on Appendix C and a nominal heat input for the turbine/duct burner combination of 2,471 MMBtu/hour, HHV. The turbine will be fired with pipeline-quality natural gas and PM emissions will be less than or equal to 16.64 lbs/hr. Based on these requirements, the turbine/duct burner will have maximum PM emissions of approximately 0.0067 lbs/MMBtu which is below the Subchapter 19 allowable. The table below shows the PM emissions for the other fuel-burning equipment on-site.

Equipment	**Maximum Heat Input (MMBtu/hr) (HHV)**	**Allowable PM Emission Rate (lbs/MMBtu)**	**Potential PM Emissions (lbs/MMBtu)**
Turbine with Duct Burner	2,471	0.152	0.0067
Auxiliary Boiler	360	0.45	0.007
Emergency Diesel Generator	7	0.6	0.32
Diesel Fire Water Pump	1.9	0.6	0.31

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The duct burner (electric utility steam generating unit) is subject to

NSPS Subpart Da and the auxiliary boiler is subject to NSPS Subpart Db. Thus, they are exempt from the opacity limit of OAC 252:100-25-3. The other emission units shown in the table above are subject to this subchapter. The auxiliary boiler will comply with this regulation by ensuring "complete combustion" and utilizing pipeline-quality natural gas as fuel. The diesel-fired units are limited to emergency use and periodic maintenance checks for a total of 500 operating hours per year. Therefore, it is very unlikely that a unit would operate for more than 24 hours at one time which is the criteria for added measures to ensure opacity compliance for diesel-fired equipment. Opacity compliance will be assured by good maintenance practices.

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. Under normal operating conditions, the facility will not interfere with the maintenance of air quality standards.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gas fuel-burning equipment, the limit is 0.2 lbs/MMBtu heat input, three-hour average. The turbine will be fired with natural gas having a maximum sulfur content of 0.30 grains per 100 cubic feet of gas (equivalent to about 0.00102 wt% sulfur) and a gross heating value of 1,020 Btu/scf, which is equivalent to approximately 0.0010 lbs/MMBtu.
Part 5 also requires an opacity monitor and sulfur dioxide monitor for equipment rated above 250 MMBtu/hr. Since the combustion turbine and auxiliary boiler are limited to natural gas only, they are exempt from the opacity monitor requirement. Based on the pipeline-quality natural gas requirement, where the natural gas burned will have less than 0.1 wt% sulfur, they are also exempt from the sulfur dioxide monitor requirement. The emergency diesel generator and diesel fire water pump will fire diesel fuel and have maximum sulfur compound emissions of 0.29 lbs/MMBtu which is well below the allowable emission limitation of 0.8 lbs/MMBtu for liquid fuels.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBtu/hr to emissions of 0.2 lbs of NO_x per MMBtu, three-hour average. The turbine/duct burner has been determined to produce maximum NO_x emissions at a rate of 0.014 lbs/MMBtu and the auxiliary boiler maximum NO_x emissions are limited to 0.036 lbs/MMBtu, demonstrating compliance with the standard of this subchapter. The auxiliary boiler, emergency diesel generator, and the diesel fire water pump are below 50 MMBtu/hr heat input and are, therefore, not subject to this regulation.

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

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The anticipated diesel tanks will have vapor pressures below the 1.5 psia threshold.
Part 5 limits the VOC content of coatings for coating lines and other 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 turbine and duct burner are designed to provide essentially complete combustion of organic materials.

OAC 252:100-41 (Hazardous Air Pollutants (HAP)) [Not Applicable]
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.

Toxic air contaminant emissions from the turbine are based on a query of the EPA emission factor database for all pollutants. Toxic emissions from the duct burner and auxiliary boiler were calculated using AP-42, Table 1.4-3 and 1.4-4, July 1998. These emissions were determined in the evaluation for Permit # 2001-205-C (PSD).

Toxic Air Pollutants From Combustion Turbine, Duct Burner and Auxiliary Boiler

		Emissions	
Pollutant	**CAS #**	**lbs/hr**	**TPY**
Acetaldehyde	75070	0.090	0.39
Acrolein	107028	0.020	0.09
Ammonia	7664417	22.46	98.37
Benzene	71432	0.02	0.10
Ethylbenzene	100414	0.05	0.22
Formaldehyde	50000	0.09	0.39
Hexane	110543	0.01	0.04
Toluene	108883	0.26	1.15
Sulfuric Acid Mist	Several	0.74	3.24
Xylene	1330207	0.10	0.44

The cooling water toxic emission rates in the following table were based upon the toxic concentrations in the circulating water at the Redbud Power Plant (Permit No. 2000-090-C (PSD)). These rates were derived from the concentrations in the raw feed water from the closest wastewater treatment plant. The Lawton Cogen facility water usage rate is approximately 35% that of Redbud's. The emission rates at Redbud were modeled and found to be comfortably under the MAAC levels, therefore, Lawton Cogen should also be in compliance with this subchapter.

Hazardous Air Pollutants (HAP) From Permit No. 2000-090-C (PSD) Cooling Water Towers		
	Emissions	
Pollutant	**lbs/hr**	**TPY**
Antimony	0.0012	0.0053
Arsenic	0.0002	0.0009
Beryllium	0.0001	0.0004
Cadmium	1.63×10^{-5}	0.00007
Chromium (1)	0.0002	0.0009
Copper	0.0002	0.0009
Lead (2)	0.0001	0.0004
Mercury	4.08×10^{-6}	0.00002
Nickel	0.0002	0.0009
Selenium	5.10×10^{-5}	0.0002
Silver	4.08×10^{-5}	0.00018
Thallium	0.0002	0.0009
Zinc	0.002	0.009

(1) All chromium is assumed to be hexavalent. (2) Lead is regulated by NAAQS.

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 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 252:100-39	Nonattainment Areas	not in a subject area
OAC 252:100-47	Landfills	not in source category

SECTION VI. FEDERAL REGULATIONS

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

NSPS, 40 CFR Part 60 [Subparts A, Da, Db and KKKK are Applicable]
Subpart A, General Provisions, requires the submittal of several notifications for NSPS-affected facilities. Within 30 days after starting construction of any affected facility, the facility must notify DEQ that construction has commenced. A notification of the actual date of initial start-up of any affected facility will be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial start-up of the facility. The facility must notify DEQ at least 30 days prior to any initial performance test and must submit the results of the initial performance tests to DEQ. The facility will comply with the notification requirements set forth in Subpart A.

Subpart Da, Electric Utility Steam Generating Units, affects steam generating units that have a heat input capacity greater than 250 MMBtu/hr, which commence construction after September 18, 1978. The HRSG duct burner meets the definition of electric utility steam generating units since it was constructed for the purpose of supplying more than one-third of their electric output capacity and more than 25 MW of electrical output to the grid for sale. Since the HRSG duct burner has a heat input capacity of up to 560 MMBtu/hr HHV and meets the definition of an electric utility steam generating unit, it is subject to Subpart Da.

Subpart Da limits the amount of PM which may be emitted from the duct burner to 0.03 lbs/MMBtu. In addition to the PM emission limit, Subpart Da sets the maximum opacity at 20 percent (six-minute average), except for one six-minute period per hour of not more than 27 percent opacity. Combustion of natural gas in the duct burner assures compliance with these opacity limits.

For facilities commencing construction after July 9, 1997, Subpart Da limits NO_X emissions (expressed as NO_2) to 0.2 lbs/MMBtu, based on a 30-day rolling average. Compliance with this limit is demonstrated as outlined in 40 CFR 60.46a(i).

Since SO_2 emissions from the duct burner will be less than 0.20 lbs/MMBtu of gross heat input, Subpart Da sets the SO_2 emission limit as 100 percent of the potential combustion concentration. This is the concentration that would result from combusting the fuel without any emission control system (i.e., no control equipment is required for units with uncontrolled emission rates less than 0.20 lbs/MMBtu).

Subpart Da does not require a continuous opacity monitor or a continuous SO_2 monitor for gaseous fuel combustion. A continuous monitoring system is required to record NO_X emissions from the duct burner. In addition, a continuous monitoring system must be installed to record oxygen or carbon dioxide concentrations at each location where NO_X emissions are measured. Gross electrical output and exhaust flow rate must be continuously monitored to demonstrate compliance with the NO_X emission limit. Performance evaluations for the monitoring systems are detailed in 40 CFR §60.47a(i).

Several compliance determination methods are required for the duct burner within 60 days after achieving the maximum production rate, but not later than 180 days after initial start-up. Method 19 is used to calculate emissions of PM and NO_X. Additional testing requirements for PM include determination of concentration (Method 5) and opacity. U.S. EPA Reference Method 9 and the procedures in 40 CFR §60.11 are used to determine the opacity of the exhaust gases. Data from the continuous monitoring system is used to compute the NO_X emission rates.

Data from the initial performance test and results of performance evaluations of the continuous monitoring system must be submitted to DEQ. 40 CFR §60.49a(b) lists data (for each 24-hour period) which must be submitted in quarterly reports to DEQ.

Reports of excess emissions and monitoring system performance must be submitted to DEQ on a quarterly basis. A period of excess emissions is defined as any six-minute period for which average opacity exceeds the applicable opacity standards. The excess emissions and monitoring system performance reports must be postmarked within 30 days after the end of the applicable reporting period. Reports may be submitted to DEQ in electronic format as described in 40 CFR §60.49a(j).

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units, lists monitoring, testing, and reporting requirements and emission standards for SO_2, PM, and NO_X for steam generating units with heat input capacities greater than 100 MMBtu/hr. The auxiliary boiler will have a heat input capacity of approximately 360 MMBtu/hr HHV and is therefore subject to Subpart Db. Since the auxiliary boiler will only combust natural gas, the only applicable requirements are to maintain a record of fuel usage and install, calibrate, maintain, and operate a continuous monitoring system for NO_x emissions. Facilities subject to Subpart Db that have commenced construction after June 19, 1986, are not subject to Subpart D.

Subpart Kb, VOL Storage Vessels, affects volatile organic liquid storage tanks constructed after July 23, 1984, with a capacity greater than or equal to 75 m^3 (19,813 gals). Subpart Kb provides design standards along with monitoring, reporting, and recordkeeping requirements. The largest diesel storage tank will have a capacity of 564 gallons. Therefore, it is not subject to Subpart Kb.

Subpart GG, Stationary Gas Turbines, affects turbines which commenced construction, reconstruction, or modification after October 3, 1977, but before February 19, 2005, with a heat input at peak load of greater than or equal to 10 MMBtu/hr.

Subpart KKKK, Stationary Combustion Turbines, affects turbines which commenced construction, reconstruction, or modification after February 18, 2005, with a heat input at peak load of greater than or equal to 10 MMBtu/hr. The proposed combustion turbine has heat input capacities at peak load of 1,911 MMBtu/hr (HHV) and will, therefore, be an affected source. Standards specified in this subpart for this size turbine limit NO_X emissions to 15 ppm at 15% O_2, however, the BACT requirement of 3.5 ppm_v is more stringent. Sulfur dioxide standards specified in this subpart are either of the following: 1) SO_2 emissions less than 0.90 lbs/MWh gross output, or 2) the turbine must not burn any fuel which contains total potential sulfur emissions in excess of 0.060 lbs SO_2/MMBtu heat input. For SO_2 emissions, the facility is proposing to use in the turbine only pipeline-quality natural gas. Sulfur content will be limited to 0.30 grains per 100 standard cubic feet (which is equivalent to 0.00102% by weight). 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 0.30 grains/100 scf or less.

NESHAP, 40 CFR Part 61 [Not Applicable]

There are no emissions of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, mercury, radionuclides, or vinyl chloride except for trace amounts of benzene. Subpart J, Equipment Leaks of Benzene, concerns only process streams that contain more than 10% benzene by weight. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.

NESHAP, 40 CFR Part 63 [Not Applicable]
Subpart YYYY sets forth emission limitations and operating limitations for formaldehyde from stationary combustion turbines located at major sources of HAP emissions. The facility is not a major source of HAP. Therefore, the combustion turbine is not subject to Subpart YYYY.

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

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

Since the turbine/duct burner uses Acid Rain CEMs as a monitoring device, it is exempt from the CAM requirements.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
Flammable substances used as a fuel are not considered when determining if a threshold quantity of a substance is stored on-site. The facility will not require storage of any regulated substance above the applicable threshold limits. More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
This facility is an affected source since it will commence operation after November 15, 1990, and is not subject to any of the exemptions under 40 CFR 72.7, 72.8 or 72.14. Paragraph 72.30(b)(2)(ii) requires a new source to submit an application for an Acid Rain permit at least 24 months prior to the start of operations. However, Mr. Dwight Alpern, U.S. EPA, has confirmed that the regulating agency (Oklahoma DEQ), can waive this requirement, and they have done so.

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 any required emission monitoring and reporting requirements of this part.

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

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor

vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030. This facility does not utilize any Class I & II substances.

SECTION VII. COMPLIANCE

Tier Classification And Public Review

This application has been determined to be **Tier I** based on the request for a modified construction permit for a new major stationary source that emits 250 TPY or more of pollutants subject to regulation. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant has an option to purchase the land.

Public reviews were completed for the original construction Permit Number 2001-205-C (PSD). The applicant published the "Notice of Filing a Tier III Application" in *The Lawton Constitution*, a daily newspaper in Comanche County, on January 8, 2002. The notice stated that the application was available for public review at the reference desk of the Lawton Public Library, 110 SW 4th St., Lawton, OK, and the DEQ Office at 707 North Robinson, in Oklahoma City. The "Notice of Tier III Draft Permit" was published in *The Lawton Constitution* on February 21, 2002. The notice stated that the draft permit could be reviewed at the places noted above. In addition, the notice stated that a public meeting would be held on March 25, 2002, at the Lawton Chamber of Commerce. This site is within 50 miles of the **Oklahoma-Texas** border, and Texas was notified about the draft permit. Comments were received from the public (at the meeting), but not from Texas or EPA Region VI, and can be viewed in the original permit if so desired. No changes were made to the permit as a result of the comments received.

A "Notice of Tier III Proposed Permit" was published in *The Lawton Constitution* on April 17, 2002. The notice stated that the proposed permit could be reviewed at the places noted above for a period of 20 days. There were no comments received from the public, nor from Texas or EPA Region VI.

The modified proposed permit was sent to EPA Region VI on October 27, 2006. No comments were received.

Fee Paid
Modified construction permit application fee of $1,500.

SECTION VIII. SUMMARY

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

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

ENERGETIX **Permit No. 2001-205-C (M-1)(PSD)**
Lawton Energy Cogen Facility

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on October 10, 2006. The Evaluation Memorandum, dated December 12, 2006, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

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

Combustion Turbine With Duct Burner Firing			
Pollutant	**lbs/hr**	**TPY**	**ppmvd** [1]
NO_X	33.8 [2]	148	3.5 [3]
CO	86.3	378	16.38
VOC	8.1	36	1.2 [4]
SO_2	2.1	9	N/A
PM_{10}	16.64	73	N/A
H_2SO_4	0.7	3	N/A
Ammonia	--	--	10 [5]

[1] corrected to 15% O_2
[2] three-hour rolling average
[3] twelve-month rolling average
[4] as methane
[5] with or without duct burners firing

Pollutant	**Auxiliary Boiler (360 MMBtu/hr) (HHV)**		**Emergency Diesel Generator (1,005 hp)**		**Diesel Fire Water Pump (268 hp)**		**Cooling Tower**	
	lbs/hr	**TPY**	**lbs/hr**	**TPY**	**lbs/hr**	**TPY**	**lbs/hr**	**TPY**
NO_X	12.96	19.44	31.18	7.80	8.31	2.08	---	---
CO	26.64	39.96	6.72	1.68	1.79	0.45	---	---
VOC	1.94	2.91	2.48	0.62	0.66	0.17	---	---
SO_2	0.32	0.48	2.06	0.52	0.55	0.14	---	---
PM_{10}	2.48	3.73	2.21	0.55	0.59	0.15	6.33	27.70

2. Compliance with the authorized emission limits of Specific Condition No. 1 shall be demonstrated by monitoring fuel flow to the turbine, the duct burner, the auxiliary boiler, and initial performance testing designed to satisfy the requirements of NSPS Subparts Da and KKKK and to confirm the manufacturer-guaranteed emission factors. Usage of only commercial-grade natural gas is limited to 8,882,640 MMBtu at the combustion turbine and 4,134,720 MMBtu at the HRSG duct burner, 12-month rolling totals. [OAC 252:100-8-6(a)(3)]

3. A serial number or other acceptable form of permanent (non-removable) identification shall be on the turbine. [OAC 252:100-43]

4. Upon issuance of an operating permit, the permittee shall be authorized to operate the combustion turbine with associated HRSG, duct burner and cooling tower continuously (24 hours per day, every day of the year). The auxiliary boiler shall be limited to 3,000 hours per 12-month rolling period. The emergency diesel generator and fire water pump shall be limited to 500 hours each of operation per 12-month rolling period. [OAC 252:100-8-6(a)]

5. The permittee shall incorporate the following BACT methods for reduction of emissions. Emission limitations are as stated in Specific Condition No. 1. [OAC 252:100-8-34]

a. The combustion turbine and duct burner shall be equipped with dry low-NO_X combustors and Selective Catalytic Reduction (SCR), or other means to achieve the same or less levels of emissions.
b. The auxiliary boiler shall also be equipped with dry low-NO_X burners.
c. Emissions from the auxiliary boiler, emergency generator and fire water pump engine shall be controlled by properly operating per manufacturer's specifications, using specified fuel types and remaining within the limits as listed in Specific Condition #1.

6. The turbine is subject to the federal New Source Performance Standards (NSPS) for Stationary Gas Turbines, 40 CFR Part 60, Subpart KKKK, and shall comply with all applicable requirements, including: [40 CFR §§ 60.4300-4420]

a. 60.4320: Standard for nitrogen oxides
b. 60.4330: Standard for sulfur dioxide
c. 60.4340-55: Monitoring of operations
d. 60.4400-15: Test methods and procedures

Since pipeline-quality natural gas will be used exclusively, monitoring for sulfur shall be with 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 0.30 grains/100 scf or less.

7. The duct burner is subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart Da, and shall comply with all applicable requirements. [40 CFR §§ 60.42a-49a]

a. 60.44a: Standard for nitrogen oxides
b. 60.46a: Compliance and performance test methods and procedures for nitrogen oxides
c. 60.47a: Emission monitoring
d. 60.49a: Reporting and recordkeeping requirements

8. The auxiliary boiler is subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart Db, and shall comply with the following requirements:
[40 CFR § 60.48b(b) & § 60.49b(d)]

a. install, calibrate, maintain, and operate a continuous monitoring system for NO_x emissions.
b. maintain a record of the amount of natural gas burned each day and calculate the annual capacity factor for each calendar quarter.

9. The permittee shall comply with all acid rain control permitting requirements and for SO_2 emission allowances and SO_2, NO_X and O_2 continuous emissions monitoring and reporting.
[40 CFR Parts 72, 73, 75]

10. Within 60 days of achieving maximum power output from the turbine generator set, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with Subpart KKKK for the combustion turbine, Subpart Da for the duct burner, and Subpart Db for the auxiliary boiler.

a. The permittee shall conduct NO_x, CO, PM_{10}, and VOC testing on the turbine at the 50% and 100% operating rates, with testing at the 100% turbine load to include testing at both a 70% and 100% duct burner operating rate. NO_x and CO testing shall also be conducted on the turbine at two additional intermediate points in the operating range, pursuant to 40 CFR §60.335(c)(2). Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(d).

b. The permittee shall conduct sulfuric acid mist testing on the turbine and duct burner at the 100% operating rate of both the turbine and duct burner. Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(d).

c. The permittee shall conduct formaldehyde testing on the turbine at the 50% and 100% operating rates, without the duct burner operating.

d. The permittee may report all PM emissions measured by USEPA Method 5 as PM_{10}, including back half condensable particulate. If the permittee reports USEPA Method 5 PM emissions as PM_{10}, testing using USEPA Method 201 or 201A need not be performed.

e. Performance testing shall be conducted while the new unit is operating within 10% of the desired testing rates. Testing protocols shall describe how the testing will be performed to satisfy the requirements of the applicable NSPS. The permittee shall provide a copy of the testing protocol, and notice of the actual test date, to AQD for review and approval at least 30 days prior to the start of such testing.

f. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4:	Determination of Moisture in Stack Gases.
Method 5:	Determination of Particulate Emissions from stationary sources.
Method 6C:	Quality Assurance procedures (Range and Sensitivity, Measurement System Performance Specification, and Measurement System Performance Test Procedures) shall be used in conducting Method 10.
Method 8:	Sulfuric Acid Mist.
Method 10:	Determination of Carbon Monoxide Emissions from Stationary Sources.
Method 20:	Determination of Nitrogen Oxides and Oxygen Emissions from Stationary Gas Turbines.
Method 25/25A:	Determination of Non-Methane Organic Emissions From Stationary Sources.
Method 201/201A:	Determination of PM_{10} Emissions
Method 320:	Vapor Phase Organic & Inorganic Emissions by Extractive FTIR

11. When CEMS data shows turbine exhaust emissions in excess of the lb/hr limits in Specific Condition Number 1, the permittee shall comply with the provisions of OAC 252:100-9 for excess emissions during start-up, shutdown, and malfunction of air pollution control equipment. Requirements of OAC 252:100-9 include immediate notification and written notification of Air Quality and demonstrations that the excess emissions meet the criteria specified in OAC 252:100-9. [OAC 252:100-9]

12. 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 252:100-8-6(a)(3)(B)]

a. Operating hours for the auxiliary boiler, emergency generator and diesel fire water pump (monthly and 12-month rolling total).
b. Total fuel consumption for the turbine and heat recovery steam generator duct burner (monthly and 12-month rolling total).
c. Sulfur content of natural gas (see Condition #6) and each delivery of diesel fuel (supplier statements).
d. Diesel fuel consumption for the emergency generator and diesel fire water pump (total annual).
e. CEMS data required by the Acid Rain program.

13. The permittee shall apply for a Title V operating permit and an Acid Rain permit within 180 days of operational start-up.

14. No emissions from other than the turbine shall be discharged which exhibit greater than 20% opacity except for short-term occurrences not to exceed six minutes in any 60 minutes nor 18 minutes in any 24-hour period; in no case shall opacity exceed 60%. Emissions from the duct burner and auxiliary boiler are subject to NSPS opacity standards, and thus exempt from this requirement. [OAC 252:100-25]

15. The fire water pump and emergency generator shall be fitted with non-resettable hour-meters. [OAC 252:100-8-6(a)]

16. No later than 30 days after each anniversary date of the issuance of this permit, 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), (C) & (D)]

a. Operating hours for the auxiliary boiler, emergency generator and diesel fire water pump (monthly and 12-month rolling total).
b. Total fuel consumption for the turbine and heat recovery steam generator duct burner (monthly and 12-month rolling total).
c. Sulfur content of natural gas (see Condition #6) and each delivery of diesel fuel (supplier statements).
d. Diesel fuel consumption for the emergency generator and diesel fire water pump (total annual).
e. CEMS data required by the Acid Rain program.

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):

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

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

SECTION XIV. EMERGENCIES

A. Any 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, 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 December28, 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]