OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **May 29, 2002**

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

THROUGH: David Schutz, P.E., New Source Permits Unit

THROUGH: Eric Milligan, P.E., New Source Permits Unit

THROUGH: Peer Review

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

SUBJECT: Evaluation of Permit Application No. **2001-205-C (PSD)**
Energetix, LLC
Lawton Energy Cogen Facility
Section 31, T2N, R12W, Lawton, Comanche County
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 an electric power generation facility (SIC Code 4911) with a nominal capacity of 308 MW on a 26-acre site in Comanche County. 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.

Potential Emission Rates for PSD Regulated Pollutants

Pollutant	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.

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 two (2) G.E. Frame 7EA combustion turbines (CTs) equipped with duct burners (DBs), two (2) heat recovery steam generators (HRSGs), 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 GE7EA CTs each have a nominal heat input of approximately 1,014 million British thermal units per hour (MMBtu/hr) high heating value (HHV), while each DB has a nominal heat input of 472 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 CTs and DBs will fire only pipeline-quality natural gas. In addition to the CTs 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 HRSGs 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.

SECTION III. EMISSIONS

Emission factors for the turbines are based on manufacturer's data. NO_x and CO values for the turbines are based on parts per million by volume, dry basis, corrected to 15% oxygen. Energetix requests that each 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 vendor's data: 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	Single CT w/Duct Burner		Two CTs w/Duct Burners		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	lbs/hr	TPY
NO_X	18.72	82.00	37.44	164.00	12.96	19.44	22.40	5.60	3.97	0.99	---	---
CO	103.42	453.00	206.84	906.00	26.64	39.96	5.95	1.49	0.86	0.21	---	---
VOC	13.47	59.00	26.94	118.00	1.98	2.97	0.63	0.16	0.32	0.08	---	---
SO_2	2.51	11.00	5.02	22.00	0.22	0.32	0.07	0.02	0.26	0.07	---	---
PM_{10}	20.30	89.00	40.60	178.00	2.48	3.73	0.70	0.18	0.28	0.07	4.34	19.00
H_2SO_4	0.78	3.40	1.55	6.80	---	---	---	---	---	---	---	---

The proposed plant is estimated to emit a maximum of 3.23 tons per year of total HAPs and a maximum of 1.19 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 turbines are from AP-42 (4/00), Table 3.1-3. HAP emission factors for the duct burners 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 burners 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

	Turbines	Duct Burners	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	0.31	0.31	0.0400	0.0001	---	0.66
Hexane	---	0.08	0.0106	---	6.31E-05	0.09
Toluene	1.18	0.01	0.0018	0.0006	1.11E-05	1.19
Xylenes	0.48	---	---	0.0003	6.26E-06	0.48
Total HAPs	**2.76**	**0.41**	**0.0541**	**<<0.01**	**<<0.0001**	**3.23**

SECTION IV. PSD REVIEW

The proposed facility will have potential emissions above the PSD significance levels for NO_x, CO, PM, PM_{10}, and VOC. 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 emissions unit for each pollutant, which exceeds an applicable PSD Significant Emission Rate (SER). Since the NO_X, CO, PM_{10}, and VOC 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 emissions source. After determining whether any NSPS is applicable, the first step in this approach is to determine for the emission unit in question the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically infeasible for the unit in question, the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical or environmental concerns. The remaining technologies are evaluated on the basis of operational and economic effectiveness. 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), particulates less than or equal to 10 microns in diameter (PM_{10}), and volatile organic compounds (VOC). 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 turbines, duct burners, the auxiliary boiler, and the cooling towers. 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 turbines with duct burners firing.

Pollutant	Technology
NO_x	$SCONO_X$™ Selective Catalytic Reduction (SCR) Dry Low NO_x Combustors Selective Non-Catalytic Reduction (SNCR)

Pollutant	Technology
NO_x	Water/steam Injection Good Combustion Practices
CO	Catalytic Oxidation Good Combustion Practices
PM_{10}	Good Combustion Practices Fuel Specification: Clean-Burning Fuels
VOC	Catalytic Oxidation Good Combustion Practices

- 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	SCONOX™ Selective Catalytic Reduction (SCR) Dry Low NO_x Combustors Selective Non-Catalytic Reduction (SNCR) Water/steam Injection Good Combustion Practices	70-95 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
VOC	Catalytic Oxidation Good Combustion Practices	60-80 Base Case

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

<u>NO_x Control Technologies</u>

The proposed turbines and duct burners will be subject to NSPS Subparts GG and Da, respectively. Subpart GG provides a NO_x limit based on heat input and fuel nitrogen content. 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.

SCONOx™ is an emerging technology for NO_x control offered exclusively by the ABB ALSTOM POWER (AAP) Environment Segment for application to turbines in excess of 100 MW (SCONOx™ is offered by Goal Line Technologies for turbines smaller than 100 MW). SCONOx™ reduces NO_x emissions by oxidizing NO to NO_2 over a catalyst and absorbing the NO_2 produced into the catalyst's potassium carbonate coating. A typical SCONOx™ system may contain 10 to 15 catalyst blocks. The catalyst blocks are configured in horizontal rows of louvers. The louvers open during normal operation to allow the exhaust gas to pass through the catalyst structure. Approximately 20% of the louvers are closed at any given time for catalyst regeneration. Catalyst regeneration is achieved by passing a dilute hydrogen-containing gas over the catalyst coating. The regeneration gas converts absorbed NO_2 to water and elemental nitrogen, leaving the catalyst coating free to absorb additional NO_2. Since only a fraction of the louvers are closed during this process, normal operation of the unit is unaffected during catalyst regeneration.

In November 1998 the California Air Resources Board (CARB) issued an evaluation of Goal Line Technologies' claim that SCONOx™ reduces NO_x levels to 2.0 ppmvd at 15% O_2 for a 34-MW GE LM2500 natural gas-fired combined cycle turbine. The evaluation report concluded that the SCONOx™ unit was capable of reducing NO_x emissions to 2.0 ppmvd; however, the report also stated that the results of the evaluation only apply to 34-MW GE LM2500 units employing water injection. Evaluations of AAP's SCONOx™ technology for large-scale turbines (e.g., the turbines proposed to be employed at the facility) have not yet been conducted and published. According to the CARB report, factors such as exhaust flow distribution and variation in turbine size and configuration may pose technical challenges for scale-up of the technology.

The CARB report does not show SCONOx™ to be a dependable control technology for the facility based on a number of factors. First, the CARB report does not address the long-term reliability of the technology since the evaluation was based on only seven months of data. An extended evaluation over the life cycle of the catalyst would be needed to demonstrate the long-term durability of this technology.

The large number of moving parts associated with the louvers used to regulate exhaust flow through the catalyst blocks creates a significant concern for the long-term mechanical operability of SCONOx™ units. Since these parts are in service in a hostile environment, frequent maintenance may be required to keep the moving components operable.

In addition, the report points out that the proprietary SCONOx™ catalyst is extremely sensitive to the presence of sulfur and can be poisoned by even trace amounts of sulfur in the exhaust. Thus, for optimum operation, natural gas fuel must be scrubbed to remove sulfur prior to combustion.

Although SCONOx™ has the potential for successful NO_x reduction, this technology is not listed as BACT for any facility in the RBLC database. SCONOx™ technology has not yet been demonstrated as effective for long-term application to large, commercial-scale combustion turbines. In addition, NO_x control with SCONOx™ technology is not economically feasible. An economic analysis for SCONOx™ based on vendor information, without including costs associated with a sulfur scrubber system, estimates the cost for SCONOx™ at $30,001 per ton of NO_x removed. This cost level is considered to be economically infeasible for BACT. Due to the high cost and lack of data supporting long-term reliability, SCONOx™ technology is not selected as BACT for control of NO_x emissions from the turbines and duct burners.

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 duct burners firing.

Energetix proposes NO_X BACT limits (at 100% load) of 3.5 ppmvd at 15% O_2 for the turbines 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.

<u>NO_xOUT</u> 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 ^{o}F. 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.

<u>Water or steam injection</u> 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.

<u>Dry Low NO_X (DLN)</u> 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 turbines and can achieve NO_x emissions as low as 9 ppmvd for the turbines alone. The combined cycle turbine system with DLN combustion and duct burners 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 ($/ton)	Technological Feasibility	Selection/Rejection
Thermal DeNO_x	--	not feasible	not demonstrated on combustion turbines
SCONO$_X$™	$30,001	feasible	not economically justifiable
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 0.05 lbs/MMBtu. No adverse environmental or economic impacts are associated with this NO_x control technology.

CO Control Technologies

The combustion turbines and duct burners are subject to NSPS Subparts GG 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:

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

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 31.91 ppmvd at 15% O_2 for the turbines and duct burners.

PM_{10} Control Technologies

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

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 turbines and duct burners combined are 0.0136 lbs/MMBtu.

VOC Control Technologies

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

Catalytic Oxidation

The formation of VOC in combustion units depends primarily on the efficiency of combustion. Inefficient combustion leads to the formation of aldehydes, aromatic carbon compounds, and various other organic compounds by several mechanisms. Catalytic oxidation decreases VOC emissions by facilitating the complete combustion of organic compounds to water and carbon dioxide. Prior to entering the catalyst bed where the oxidation reaction occurs, the exhaust gas must be pre-heated to about 400 to 800 ^{o}F.

The RBLC database shows few instances of catalytic oxidation being selected as BACT for VOC at any gas-fired turbine power plant nationwide. An economic analysis for the catalytic oxidation of VOC emissions based on vendor information estimates the cost at $30,811 per ton of VOC removed. This cost level is economically infeasible for VOC removal. Thus, catalytic oxidation is not selected as BACT for VOC emissions from the proposed turbines and duct burners.

Good Combustion Practices

All BACT determinations for VOC in the RBLC outside of California and New York show the use of combustion control or good combustion practices. Energetix proposes good combustion practices as BACT for VOC, with limits of 7.25 ppmvd at 15% O_2, as methane.

BACT Selection

Based on the BACT analysis presented above, the table following summarizes the BACT determinations for the turbines and duct burners. 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 TURBINES AND DUCT BURNERS AT 100% LOAD

Pollutant	BACT Determination	Emission Limits
NO_x	SCR (with duct burners firing) SCR (without duct burners firing)	3.5 ppmvd @ 15% O_2 3.5 ppmvd @ 15% O_2
CO	Good Combustion Practices	31.91 ppmvd @ 15% O_2
PM_{10}	Good Combustion Practices	0.0136 lbs/MMBtu
VOC	Good Combustion Practices	7.25 ppmvd @ 15% O_2

<u>BACT Evaluation for Auxiliary Boiler</u>

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.

<u>BACT Evaluation for Cooling Tower</u>

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 towers 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 towers, with a PM_{10} BACT limit of 0.482 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) instead of the two 7EA turbines 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 smaller turbines 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 current design. The revised 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/m^3)	**(μg/m^3)**	**(μg/m^3)**
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**
	(μg/m³)	**(μg/m³)**	**(μg/m³)**	**(μg/m³)**
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 filed 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 facilities 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

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 Concentrations**	**Modeling Significance Level**
		(μg/m^3)	**(μg/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 permit a permit nor evaluate it's 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 exist on July 1, 2000, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. The HRSGs will be subject to Subpart Da, the auxiliary boiler will be subject to Subpart Db, and the turbines will be subject to Subpart GG. NSPS regulations 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 252:100-7 (Permits for Minor Facilities) [Not Applicable]
Subchapter 7 sets forth the permit application fees and the basic substantive requirements for permits for minor facilities. The current project will be a major source that is subject to Subchapter 8 permitting.

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
- 0.6 TPY of any one Category A toxic substance
- 1.2 TPY of any one Category B toxic substance
- 6.0 TPY of any one Category C toxic substance

Emissions limitations 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. Part 70 sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable; but under no circumstances shall notification be more than 24 hours after the exceedance.

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 0.153 lbs/MMBtu based on Appendix C and a nominal heat input of the turbine/duct burner combination 1,486 MMBtu/hour, HHV. Each turbine will be fired with pipeline-quality natural gas and PM emissions will be less than or equal to 20.3 lbs/hr per unit. Based on these requirements, the turbines/duct burners will have maximum PM emissions of approximately 0.0136 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)
Auxiliary Boiler	360	0.26	0.007
Emergency Diesel Generator	7	0.6	0.08
Diesel Fire Water Pump	0.9	0.6	0.01

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 burners (electric utility steam generating units) are 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 emissions units shown in the table above are subject to this subchapter. These units will comply with this regulation by ensuring "complete combustion" and utilizing pipeline-quality natural gas as fuel.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. 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 turbines will be fired with natural gas having a maximum sulfur content of 0.55 grains per 100 cubic feet of gas (equivalent to about 0.00175 wt% sulfur) and a gross heating value of 1,012 Btu/scf, which is equivalent to approximately 0.0017 lbs/MMBtu.
Part 5 also requires an opacity monitor and sulfur dioxide monitor for equipment rated above 250 MMBtu/hr. Since the combustion turbines 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

turbines/duct burners have been determined to produce maximum NO_x emissions at a rate of 0.013 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 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 turbines and duct burners are designed to provide essentially complete combustion of organic materials.

OAC 252:100-41 (Hazardous and Toxic Air Contaminants) [Applicable - State Only]
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2000, 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, CC, DD, EE, GG, HH, II, JJ, LL, KK, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV and XXX are hereby adopted by reference as they exist on July 1, 2000. These standards apply to both existing and new sources of HAPs. NESHAP are addressed in the "Federal Regulations" section.
Part 5 is a state-only requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category "A" pollutant above de minimis levels must perform a BACT analysis and, if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant that exceeds the de minimis level do not cause or contribute to a violation of the MAAC. Formaldehyde and sulfuric acid mist are the only category A pollutants which exceed the de minimis level. For this application, the very low level of toxic emissions means that there are no available control technologies that would provide cost effective environmental benefits. Therefore, BACT for formaldehyde and sulfuric acid mist is proposed as no add-on controls.

Toxic air contaminant emissions from the turbines are based on a query of the EPA emission factor database for all pollutants. Toxic emissions from the duct burners and auxiliary boiler were calculated using Table 1.4-3 and 1.4-4, July 1998.

Toxic Air Pollutants From Combustion Turbines, Duct Burners and Auxiliary Boiler

		Toxic	De Minimis Levels		Emissions	
Pollutant	**CAS #**	**Category**	**lbs/hr**	**TPY**	**lbs/hr**	**TPY**
Acetaldehyde	75070	B	1.10	1.20	0.090	0.39
Acrolein	107028	A	0.57	0.60	0.020	0.09
Ammonia	**7664417**	**C**	**5.60**	**6.00**	**39.60**	**173.45**
Benzene	71432	A	0.57	0.60	0.02	0.10
Ethylbenzene	100414	C	5.60	6.00	0.05	0.22
Formaldehyde	**50000**	**A**	**0.57**	**0.60**	**0.15**	**0.66**
Hexane	110543	C	5.60	6.00	0.02	0.09
Propylene Oxide	75569	A	0.57	0.60	0.197	0.863
Toluene	108883	C	5.60	6.00	0.27	1.19
Sulfuric Acid Mist	**Several**	**A**	**0.57**	**0.60**	**1.55**	**6.81**
Xylene	1330207	C	5.60	6.00	0.11	0.48

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 (HAPS) From Permit No. 2000-090-C (PSD) Cooling Water Towers					
	Toxic	**De Minimis Levels**		**Emissions**	
Pollutant	**Category**	**lbs/hr**	**TPY**	**lbs/hr**	**TPY**
Antimony	B	1.10	1.20	0.0012	0.0053
Arsenic	A	0.57	0.60	0.0002	0.0009
Beryllium	A	0.57	0.60	0.0001	0.0004
Cadmium	A	0.57	0.60	1.63×10^{-5}	0.00007
Chromium (1)	A	0.57	0.60	0.0002	0.0009
Copper	B	1.10	1.20	0.0002	0.0009
Lead (2)	(2)	N/A	N/A	0.0001	0.0004
Mercury	A	0.57	0.60	4.08×10^{-6}	0.00002
Nickel	A	0.57	0.60	0.0002	0.0009
Selenium	C	5.60	6.00	5.10×10^{-5}	0.0002
Silver	B	1.10	1.20	4.08×10^{-5}	0.00018
Thallium	A	0.57	0.60	0.0002	0.0009
Zinc	C	5.60	6.00	0.002	0.009

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

For emissions of each pollutant that exceeded a respective de minimis level, modeling was required to demonstrate compliance with the respective Maximum Ambient Air Concentration (MAAC). ISCST3 modeling was conducted for each toxic based on 1991 meteorological data and indicated the facility would be in compliance with each MAAC. Since the resulting maximum predicted concentrations were below 50% of the MAAC, no more modeling is required.

Pollutant	**CAS #**	**Emissions (lbs/hr)**	**MAAC ($\mu g/m^3$)**	**Estimated Impact ($\mu g/m^3$)**
Ammonia	7664417	39.60	1,742	8.136
Formaldehyde	50000	0.15	12	0.066
Sulfuric Acid Mist	Several	1.55	10	0.314

OAC 252:100-43 (Sampling and Testing Methods) [Applicable]
All required testing must be conducted by methods approved by the Executive Director under the direction of qualified personnel. All required tests shall be made and the results calculated in accordance with test procedures described or referenced in the permit and approved by the AQD.

OAC 252:100-45 (Monitoring of Emissions) [Applicable]
Records and reports as Air Quality shall prescribe on air contaminants or fuel shall be recorded, compiled, and submitted as specified in the permit.

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 GG 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 burners meet the definition of electric utility steam generating units since they are 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 burners have heat input capacities of up to 472.3 MMBtu/hr HHV and meet the definition of electric utility steam generating units, they are subject to Subpart Da.

Subpart Da limits the amount of PM which may be emitted from the duct burners 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 burners 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 burners 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 each 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 burners 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 GG, Stationary Gas Turbines, affects turbines which commenced construction, reconstruction, or modification after October 3, 1977, with a heat input at peak load of greater than or equal to 10 MMBtu/hr. The proposed combustion turbines have heat input capacities at peak load of 1,014 MMBtu/hr (HHV) and are, therefore, affected sources. Standards specified in Subpart GG limit NO_X emissions to a minimum of 75 ppmvd (potentially higher based on heat rate and fuel nitrogen content) for the combustion turbines. For NO_X emissions, the BACT requirement of 3.5 ppm_v for the combustion turbines is more stringent than Subpart GG requirements. Sulfur dioxide standards specified in Subpart GG are that no fuel shall be used which exceeds 0.8% by weight sulfur nor shall exhaust gases contain in excess of 150 ppm_v SO_2. For fuel supplies without intermediate bulk storage, the owner or operator shall either monitor the fuel nitrogen and sulfur content daily or develop custom schedules of fuel analysis based on the characteristics of the fuel supply; these custom schedules must be approved by the Administrator before they can be used for compliance with monitoring requirements. For SO_2 emissions, the facility is proposing to use in the turbines only pipeline-quality natural gas which will contain less than the 0.8% sulfur by weight limit. Sulfur content will be limited to 0.55 grains per 100 standard cubic feet (which is equivalent to 0.00175% by weight). Since pipeline-quality natural gas will be used exclusively, monitoring for sulfur is proposed as a quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly "stain tube" analysis.

Subpart Kb, VOL Storage Vessels, affects volatile organic liquid storage tanks constructed after July 23, 1984, with a capacity greater than or equal to 40 m^3 (10,567 gal). 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.

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 at This Time]
There is no current standard that applies to this facility. A MACT standard may be applicable under the source category "Subpart YYYY - Combustion Turbines," which is scheduled for promulgation by May 2002. Air Quality reserves the right to reopen this permit if any standard becomes applicable.

The combustion turbines are a listed MACT source category but are not subject to case-by-case MACT requirements because HAP emissions are below the 10/25 TPY thresholds. Duct burners associated with HRSGs are exempt from consideration for case-by-case MACT as explained in EPA's May 25, 2000, Interpretive Ruling on this issue.

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 turbines/duct burners use CEMs as monitoring devices, they are 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 [Applicable]
This facility does not produce, consume, recycle, import, or export any controlled substances or controlled products as defined in this part, nor does this facility perform service on motor (fleet) vehicles that involves ozone-depleting substances. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

SECTION VII. COMPLIANCE

Tier Classification And Public Review

This application has been determined to be **Tier III** based on the request for a 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.

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 are included below, along with the DEQ responses. 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 have there been any comments from Texas or EPA Region VI.

Response to Comments from Public Meeting

Comment #1:

I am here to make sure that we have on record some thoughts about how this plant will relate to the ozone problem that Lawton has. I know that a lot of air quality modeling has been done that says this plant will not create a problem. I would like to note for the record that Lawton has a problem today and county commissioners are already spending money for billboards that this summer will indicate our problem and our need to keep down our emissions. The city has already sent letters to the businesses to make sure that they too will keep down their emissions. So I think we need to recognize and be sure that when this plant is permitted that this is the plant we want to consume the really scarce increment we have left of clean air. Because in permitting this plant, it will preclude other opportunities. I'm not saying that I'm against this plant, but I think it is something that as a city we need to address very carefully to make sure this is the best use of the clean air, that there might not be another opportunity that would give us more jobs, more than 30 jobs, or greater growth for the amount of emissions that this plant is going to give us. Having said that, I would like to offer what seems to me to be at least a partial solution. The ozone problem is not a problem that is 365-days a year, it's a peak load problem, it's only a few days a year. And I think it would be wonderful if the permit for this plant contained a condition that the plant would not operate during ozone alert days. I think that way we could have both the plant and not endanger our ozone status. I've been told that such a thing has not been done in the past, hasn't been done before, but I don't see why it couldn't be done now. Certainly when natural gas was in scarse supply and we had natural gas curtailments when there was a shortage, large plants such as this power plant would shut down, and curtail their use of the natural gas. In this case, the clean air, the remaining increment that we have is the scarse resource. And when that clean air becomes scarse on the ozone alert days, it would be wonderful if the plant would shutdown so that the rest of the city would not be jeopardized in its growth ambitions. This is something I believe should be in the permit, and I would hope that Energetix would itself agree voluntarily to support this kind of condition in the permit.

Response:

Considerable air quality modeling was done in association with this facility, mostly concerning NO_x, CO, PM_{10} and VOCs. Ozone is formed by the combination of many things, NO_x and VOCs being two of them. Based on the original plant configuration, no ambient concentration limits or visibility criteria would be exceeded at the original NO_x and VOC emission rates. Therefore, with the current plant being only half the generating capacity as the original, NO_x and VOC emission rates will be even less, with commensurately less ozone formed. Lawton at this time is in an ozone attainment area, and as such, DEQ has no authority to require a plant to shutdown absent an imminent danger scenario. The preventive steps recommended on ozone alert days are voluntary and not binding on any person or facility. Should the Lawton area go nonattainment for ozone, then DEQ could have the authority to require stricter controls, curtailment of operating hours, etc. At this time, no change to limit the facility operation is or will be required.

Comment #2:

1) Concerned about the air quality but also the noise associated with the plant as I am located 1 mile north of the plant.
2) Also, is there a plant that is similar that we could drive by and see?

Responses:

1) DEQ has no authority to regulate noise; if noise is regulated in the area, it would be by local ordinance.
2) The closest similar plant is in the Oklahoma City area, next to the Bridgestone Tire plant.

Comment #3:

1) The height of the stacks in the application are 45 meters tall, is that correct?
2) Are these the same height as the stacks at Newcastle?

Responses:

1) The stack heights in the revised application to be installed at the Lawton facility are 45.72 meters for the turbines, 18.29 meters for the auxiliary boiler, and 15.24 meters for the cooling tower.
2) The stacks at Newcastle are 47.9 meters (according to the permit memorandum); however, the turbines at Newcastle are Model 7FAs, which have approximately twice the generating capacity of the 7EAs used at Lawton, so any stack flow similarities end there.

Comment #4:

1) The emissions in the paper, are they good or bad?
2) Are there any odors that will come from this plant?

Responses:

1) The emissions shown in the public notice were determined to be within all federal and state air emission guidelines, including mass emission rates from the stacks and ambient concentration limits downwind from the facility.

2) Since Energetix is using Selective Catalytic Reduction (SCR) to control the emissions of nitrogen oxides, and ammonia is used with SCR, there is always the possibility that ammonia odors could emanate from the facility. However, just as with noise, DEQ does not regulate odors. Instead, as an indicator of proper operation, the permit does restrict the amount of slip (the ammonia that gets out the stack) to no more than 10 parts per million by volume. According to published reports, the least perceptible odor value is 5 ppm, while the readily detectable odor range is 20-50 ppm. OSHA's 8-hr workshift limit is 50 ppm.

Fee Paid

Construction permit application fee of $2,000.

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 (PSD)**
Lawton Energy Cogen Facility

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on September 20, 2001, with additional information submitted September 25 and December 27, 2001, and January 30, 2002. The Evaluation Memorandum, dated May 29, 2002, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

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

Each of Two Combustion Turbines With Duct Burners Firing			
Pollutant	**lbs/hr**	**TPY**	**ppmvd** [1]
NO_X	18.7 [2]	82	3.5 [3]
CO	103.4	453	31.91
VOC	13.5	59	7.25 [4]
SO_2	2.5	11	N/A
PM_{10}	15.3	67	N/A
H_2SO_4	0.8	3.4	N/A
Ammonia	--	--	10 [5]

[1] corrected to 15% O_2
[2] two-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 (1,000 hp)**		**Diesel Fire Water Pump (129 hp)**		**Cooling Towers**	
	lbs/hr	**TPY**	**lbs/hr**	**TPY**	**lbs/hr**	**TPY**	**lbs/hr**	**TPY**
NO_X	12.96	19.44	22.40	5.60	3.97	0.99	---	---
CO	26.64	39.96	5.95	1.49	0.86	0.21	---	---
VOC	1.98	2.97	0.63	0.16	0.32	0.08	---	---
SO_2	0.22	0.32	0.07	0.02	0.26	0.07	---	---
PM_{10}	2.48	3.73	0.70	0.18	0.28	0.07	4.34	19.00

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

3. A serial number or another acceptable form of permanent (non-removable) identification shall be on each turbine. [OAC 252:100-45]

4. Upon issuance of an operating permit, the permittee shall be authorized to operate each 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. Each 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. Each turbine is subject to the federal New Source Performance Standards (NSPS) for Stationary Gas Turbines, 40 CFR Part 60, Subpart GG, and shall comply with all applicable requirements, including: [40 CFR §§ 60.330-335]

a. 60.332: Standard for nitrogen oxides
b. 60.333: Standard for sulfur dioxide
c. 60.334: Monitoring of operations
d. 60.335: Test methods and procedures

A quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly "stain tube" analysis is acceptable as sulfur content monitoring of the fuel under NSPS Subpart GG. Other customary monitoring procedures may be submitted with the operating permit for consideration. Monitoring of fuel nitrogen content under NSPS Subpart GG shall not be required while commercial quality natural gas is the only fuel fired in the turbines.

7. The duct burners are 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 emissions 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 each 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 GG for the combustion turbines, Subpart Da for the duct burners, and Subpart Db for the auxiliary boiler.

a. The permittee shall conduct NO_x, CO, PM_{10}, and VOC testing on the turbines 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 turbines 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 turbines and duct burners 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 turbines at the 50% and 100% operating rates, without the duct burners 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 units are 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. NO_X and CO concentrations listed in Specific Condition No.1 shall not be exceeded except during periods of start-up, shutdown, maintenance or malfunction operations. When monitoring shows concentrations in excess of the ppm and lb/hr limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions during start-up, shutdown, and malfunction of air pollution control equipment. Requirements include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions other than periods of start-up, shutdown, maintenance or malfunction operations. [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 each turbine and heat recovery steam generator duct burner (monthly and 12-month rolling total).
c. Sulfur content of natural gas and each delivery of diesel fuel (supplier statements or quarterly "stain-tube" analysis).
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 turbines 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 burners 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 each turbine and heat recovery steam generator duct burner (monthly and 12-month rolling total).
c. Sulfur content of natural gas and each delivery of diesel fuel (supplier statements or quarterly "stain-tube" analysis).
d. Diesel fuel consumption for the emergency generator and diesel fire water pump (total annual).
e. CEMS data required by the Acid Rain program.