OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **July 28, 2003**

TO: Dawson Lasseter, Chief Engineer, Air Quality

THROUGH: Richard Kienlen, P.E., Engr. Mgr. II, New Source Permits Section

THROUGH: Peer Review, Hal Wright

FROM: Herb Neumann
Regional Office at Tulsa

SUBJECT: Evaluation of Permit Application No. **99-010-TV**
Cogentrix Energy, Inc.
Green Country Energy, LLC
Gas Turbine Electric Power Plant
NW/4 Section 4, T17N, R13E, Jenks, Tulsa County
Approximately 126th Street and Arkansas River, 4 miles east of US 75

I. INTRODUCTION

This facility began operations on February 6, 2002, under Construction Permits No. 99-010-C (PSD) and 99-010-C (PSD)(M-1). Other than a decrease in the heat input rate of the duct burners and an increase in the heat input rating of the auxiliary boiler, there are no significant variations from the evaluations and specific conditions of the construction permits. There is a single significant operating scenario. The generating facility (SIC Code 4911) consists of three combined cycle gas turbines, each with a heat recovery steam generator powering a steam turbine. The construction permit required Prevention of Significant Deterioration (PSD) analysis, and the application required Tier III public review. This permit does not alter any of the conditions, so it requires only Tier I review.

II. PROCESS DESCRIPTION

The project installed three combined cycle gas turbines firing only natural gas. Maximum rating of the entire facility is 800 MWe. Conservatively high estimates of emissions from each unit were generated using the following conditions. Each gas turbine is paired with a steam turbine powered by steam produced in a heat recovery steam generator (HRSG) from the exhaust gas from the gas turbine. The exhaust gas from each turbine can be further heated by duct burners located in the HRSG, providing additional steam to the steam turbine. Waste heat from each set of turbines is rejected through a mechanical draft counter-flow cooling tower. An auxiliary boiler provides heat to facilitate start-up for all turbines by pre-heating the steam turbines. An emergency generator serves all three units as backup in the event of a power outage. A diesel fire pump is available for emergency use. Each turbine set has a 5 MMBTUH fuel pre-heater.

The gas turbines are GE Model PG7241FA, each with a nominal output of 181.6 MWe at base conditions of 10°F, with a higher heat value (HHV) input of 1,698 MMBTUH. The turbines use dry low-NO_x combustors. A typical dry low-NO_x burner for a turbine consists of one diffusion flame pilot nozzle surrounded by several equally spaced premix flame main nozzles. The formation of NO_x is influenced by how much gas is burned in the pilot flame and how much is burned in the surrounding combustor nozzles. The multinozzle design spreads the combustion volume into a wider, cooler, less concentrated flame. Typically, for natural gas fuel, approximately 7 to 10 % by volume of the total gas flow is sent through the pilot nozzle. Other than startup, shutdown, and malfunctions, each combustion turbine is operated at or above 70 percent rated turbine load to assure operations in the "pre-mix" mode. Pre-mix is the operating mode for the burner that optimizes combustion efficiency and produces the lowest NO_x emissions. However, elevated levels of NO_x and CO can result during cold startups and/or in the "diffusion" mode. These turbines are designed to operate in the pre-mix mode almost immediately after light-off. Although cold starts can require as much as five hours to achieve fully loaded operation of each turbine set, the auxiliary boiler is used to heat the steam turbine to the proper temperature before the combustion turbine is lit. This technique allows for very quick stabilization of the set at optimum operating conditions.

The duct burners fire only natural gas at 265 MMBTUH for each unit. Each stack vents at 150' above grade and has a diameter of 18'. Combustion turbines and duct burners are authorized to operate continuously, or 8,760 hours per year.

Selective catalytic reduction (SCR) is applied to the exhaust stream by injecting ammonia downstream from the duct burners and upstream of a catalyst bed. This causes most NO_x to be converted to nitrogen and water vapor, but allows some emissions of ammonia. This process will be described in greater detail in the BACT analysis later in this memorandum.

The auxiliary boiler mentioned above is natural gas-fired and is used for steam seals and to set up a vacuum for steam turbine start, as well as to provide an alternate source of steam for facility heating. The auxiliary boiler has a rated steam output of 16,000 pounds per hour and a rated heat input of 23.6 MMBTUH. The auxiliary boiler fires a maximum of 3,000 hours per year and exhausts at 308°F through a 2′ diameter stack at 83′ above grade.

The diesel emergency generator is rated at 750 kW (8.4 MMBTUH) and the diesel fire pump is rated at 110 BHP (1.23 MMBTUH). None of these units will be operated in excess of 500 hours per year, making them insignificant sources for Title V permitting. Diesel storage tanks associated with these operations include a 100-gallon tank with the fire pump and a 300-gallon for the emergency generator.

Each of the cooling towers has four cells. Each cell vents 391,313 acfm at 85°F at 35′ above grade.

III. EQUIPMENT

EUG CC

Emission Unit	Emission Point	Equipment	Rating	Const. Date
GT1	EP1	GE PG7241 FA NG-fired combustion turbine	181.6 MW	2/6/02
GT2	EP2	GE PG7241 FA NG-fired combustion turbine	181.6 MW	2/6/02
GT3	EP3	GE PG7241 FA NG-fired combustion turbine	181.6 MW	2/6/02
DB1	EP1	Duct burner	265 MMBTUH	2/6/02
DB1	EP2	Duct burner	265 MMBTUH	2/6/02
DB1	EP3	Duct burner	265 MMBTUH	2/6/02

EUG AUX1

Emission Unit	Emission Point	Equipment	Rating	Const. Date
AB1	EP4	Clayton natural gas-fired auxiliary boiler	23.6 MMBTUH	2/6/02

The facility identifies EUG CT for the cooling towers, but this activity is trivial per OAC 252:100 Appendix J.

IV. EMISSIONS

This project involves a number of emission points. Emissions are generated by combustion at the turbines, at the duct burners, at the auxiliary boiler, and to a much smaller extent at the fuel pre-heaters, emergency generator, and fire pump. Each HRSG stack exhausts combustion emissions from its duct burners and related turbine. Very small emissions of VOC are expected from the diesel storage tank. Ammonia is supplied to the SCR process in amounts slightly above the stoichiometric requirement, so there are some emissions of ammonia, called "ammonia slip," in the exhaust. Since calculations below show the facility exceeds the significance threshold for emissions of PM_{10}, NO_X, CO, SO_2 and VOC, the project was subject to full PSD review. Tier III public review, best available control technology (BACT), and ambient impacts analyses were also required.

The following table displays emissions based on best available data. Emission factors for the turbines and HRSGs are based on manufacturer's guarantees. Pollutant concentrations in exhaust gases differ between turbine-only and turbine-duct burner cases. The applicant expects normal operating mode to include the duct burners, but they will be used as demands for power require. Each factor is listed, but the higher factor is used as a conservative estimate of emissions for the project. Note that the NO_x and CO values for the turbines (without duct burners) are based on ppmv dry at 15% O_2. The applicant has chosen a conservatively high estimate of six pounds of SO_2 per MMSCF. The initial application showed emissions of 2.67 lbs/hr of TSP (all considered to be PM_{10}) from the duct burners, but these data were updated to show a corrected manufacturer's guarantee of 5.3 lbs/hr from the duct burners, implying total emissions of 18 + 5.3 = 23.3 lbs/hr from each turbine with the duct burners on.

	Emissions per manufacturer		Equivalent emission factor			Totals for 3 turbine sets	
Pollutant	CT alone	CT w/duct burner	ppmvd	Lb/MMBTU	Lb/hr/set	Lb/hr	TPY
NO_x	4.5 ppmvd	61 lb/hr	10.8	0.031	61	183	801.54
CO	9 ppmvd	61 lb/hr	17.4	0.031	61	183	801.54
SO_2	0.006 lb/MMBTU	0.006 lb/MMBTU		0.006	11.99	35.96	157.52
VOC	15 lb/hr	15.60 lb/hr	7.62 w	0.0078	15.60	46.80	204.98
TSP = PM_{10}	18 lb/hr	23.3 lb/hr		0.0117	23.3	69.9	306.20

w indicates saturated rather than dry

Emissions from the auxiliary boiler are calculated using factors from AP-42 (3/98) Tables 1.4-1 & 2 except for SO_2, where the facility again uses a conservatively high estimate of six pounds per MMCF. The auxiliary boiler is rated at 23.6 MMBTUH and is limited to 3,000 hours of operation per year. Heating value of the gas is taken to be 1,020 BTU/CF.

	Factor	Emissions	
Pollutant	Lb/MMCF	Lb/hr	TPY
NO_X	50	1.16	1.74
CO	84	1.94	2.92
SO_2	6	0.14	0.21
VOC	5.5	0.13	0.19
TSP=PM_{10}	7.6	0.18	0.26

Emissions from the emergency generator and diesel fire pump are calculated using factors from AP-42 (1/95) Tables 3.3-2 for uncontrolled diesel industrial engines less than 600 bhp. The 750 kW generator is rated at 8.4 MMBTUH and the diesel fire pump is rated at 1.23 MMBTUH. The generator and fire pump are limited to 500 operating hours each per year. Emissions from the three 300-gallon and one 100-gallon diesel storage tanks are insignificant.

Pollutant	Factor (Lb/MMBTU)	Emissions (Lb/hr)		Emission total TPY
		Generator	Fire pump	
NO_X	4.41	37.04	5.42	10.62
CO	0.95	7.98	1.17	2.29
SO_2	0.29	2.44	0.36	0.70
VOC	0.36	3.02	0.44	0.87
TSP=PM_{10}	0.31	2.60	0.38	0.75

The three fuel pre-heaters are treated as a single 15 MMBTUH source for calculating emissions, using factors from Tables 1.4-1 and 2 of AP-42 (7/98). Continuous operation is assumed.

	Factor	Emissions	
Pollutant	Lb/MMCF	Lb/hr	TPY
NO_X	100	1.47	6.44
CO	84	1.24	5.41
SO_2	0.6	0.01	0.02
VOC	5.5	0.05	0.20
PM_{10}	7.6	0.06	0.28

Emissions from the cooling tower were calculated assuming a drift ratio of 0.002% and total dissolved solids (TDS) of 12,000 ppm. Combining three towers of four cells each yields 9.61 lb/hr or 42.11 TPY of TSP. EPRI's report titled User's Manual – Cooling Tower Plume Prediction states on page 4-1 that this particulate ranges in size between 20 and 30 μ, thus none of the TSP is PM_{10}. Non-contact cooling towers are considered to be trivial sources, so these calculations are presented only for completeness.

HAPs and toxics

The following table reviews emissions of ammonia, sulfuric acid and HAPs from the turbine sets. The ammonia slip emission factor is guaranteed not to exceed 10 ppm. Calculations for sulfuric acid emissions are found in AP-42 (9/98) Section 1.3.3.2. Although this Section of AP-42 deals with liquid fuels, the discussion makes clear that the formation of acid mist is a function of SO_2 availability and is not a function of burner design or fuel. Worst case assumptions for acid mist from SO_2 formation include an average annual sulfur content of 0.25 gr/100 dscf and an hourly high of 5 gr/100 dscf, along with an average formation rate of acid mist at 3% annually and 5% hourly. Heating value of the gas is taken to be 1,020 BTU/CF. Speciated HAP emission factors are taken from Tables 3.1-3 and 4 of AP-42 (4/00). Formaldehyde is treated separately in the third table following. The facility has chosen to use formaldehyde database factors accepted by California Air Resources Board for these types of equipment.

		Toxic		Emissions		
Pollutant	HAP	Cat.	Emission factor	Lb/hr/set	Total lb/hr	Total TPY
Ammonia	No	C	10 ppm	22.300	66.900	293.022
Sulfuric acid	Yes	A	Per SO_2 formation	2.143	6.429	0.845
1,3-Butadiene	Yes	A	4.3×10^{-7} lb/MMBTU	0.001	0.003	0.011
Acetaldehyde	Yes	B	4.0×10^{-5} lb/MMBTU	0.079	0.236	1.032
Acrolein	Yes	A	6.4×10^{-6} lb/MMBTU	0.013	0.038	0.165
Benzene	Yes	A	1.2×10^{-5} lb/MMBTU	0.024	0.071	0.310
Ethylbenzene	Yes	C	3.2×10^{-5} lb/MMBTU	0.063	0.188	0.825
Naphthalene	Yes	B	1.3×10^{-6} lb/MMBTU	0.003	0.008	0.034
PAHs*	Yes	A	2.2×10^{-6} lb/MMBTU	0.004	0.013	0.057
Propylene oxide	Yes	A	2.9×10^{-5} lb/MMBTU	0.057	0.171	0.748
Toluene	Yes	C	1.3×10^{-4} lb/MMBTU	0.255	0.766	3.353
Xylene	Yes	C	6.4×10^{-5} lb/MMBTU	0.126	0.377	1.651

Similarly, speciated emissions are also calculated for the other combustion sources using AP-42 (3/98) Table 1.4-3 for the auxiliary boiler and AP-42 (1/95) Table 3.3-3 for the diesel engines. Other tables were reviewed, but only those factors giving rise to a minimum of one pound per year are shown here. The auxiliary boiler is rated at 22 MMBTUH and is limited to 3,000 hours of operation per year. Heating value of the gas is taken to be 1,020 BTU/CF. The combined heat rate of the generator and the fire pump is 9.63 MMBTUH. The generators and fire pump are limited to 500 operating hours per year.

				Emissions	
Pollutant	HAP	Cat	Factor	Lb/hr	TPY
Hexane	Y	C	1.8 lb/MMCF	0.039	0.058

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	CARB emission factor	Emissions	
Equipment	(Lb/MMBTU)	Lb/hr	TPY
Combustion turbines (3)	0.000110	0.560	2.454
Duct burners (3)	0.0000735	0.058	0.256
Auxiliary boiler	0.0000735	0.002	0.003
Diesel generator	0.00118	0.010	0.002
Diesel fire pump	0.00118	<.001	<.001
Preheaters (3)	0.0000735	0.001	0.005
Totals		0.631	2.720

The total of all HAP is 11.81 TPY, and no single HAP has emissions greater than or equal to 10 TPY, so the facility is not major under the definition of 40 CFR 63. Note that seven chemicals from the three preceding tables (ammonia, acetaldehyde, benzene, formaldehyde, naphthalene, PAHs and propylene oxide) exceed their respective Category *de minimis* thresholds. Further discussion is found under OAC 252:100-41 below.

V. PSD REVIEW

As-built corrections have the effect of slightly decreasing overall emissions. These include downsizing the three duct burners from 300 MMBTUH each as proposed to 265 MMBTUH each as installed, increasing the auxiliary boiler from 20.9 MMBTUH to 23.6 MMBTUH, and the addition of three 5 MMBTUH fuel preheaters. The net effect of these changes is not sufficient to alter emission totals relative to PSD significance levels, so the PSD analysis performed at the original levels is reproduced here verbatim from the construction permit.

Pollutant	NO_X	CO	SO_2	VOC	PM_{10}	H_2SO_4	Lead
Project emissions (TPY)	806.20	804.79	157.91	205.41	272.05	0.85	0.41
Significance level (TPY)	40	100	40	40	15	7	0.6
PSD Review required?	Yes	Yes	Yes	Yes	Yes	No	No

As the analysis above indicates, PSD review is required for emissions of NO_X, CO, SO_2, VOC, and PM_{10} due to this project. Full PSD review of emissions consists of the following.

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

A. Best Available Control Technology (BACT)

The emission units for which a BACT analysis is required include the combustion turbines, auxiliary boiler, emergency diesel generator, diesel fire pump and cooling towers and will be discussed in this order. Economic as well as energy and environmental impacts are considered in a BACT analysis. The EPA-required top down BACT approach must look not only at the most stringent emission control technology previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc. These technologies and emissions data are identified through a review of EPA's RACT/BACT/ LAER Clearinghouse (RBLC). If the proposed BACT is equivalent to the most stringent emission limit, no further analysis is necessary. However, if the most stringent emission limit is not selected, additional analyses are required.

Once the most stringent emission control technology has been identified, its technical feasibility must be determined, hence the term "available" in Best Available Control Technology (BACT). A technology that is available and is applicable to the source under review is considered technically feasible. A control technique is considered available if it has reached the licensing and commercial sales stage of development. In general, a control option is considered applicable if it has been, or is soon to be, developed on the same or similar source type.

If the control technique is feasible, that control is considered to be BACT unless economic, energy, or environmental impacts preclude its use. This process defines the "best" term in Best Available Control Technology. Therefore, if the chosen technology is not applicable or is technically or economically infeasible for the source in question, the next most stringent control technology is evaluated. The process continues until an emission level cannot be eliminated.

When the most stringent technically feasible control technology is not selected as BACT, justification must be provided in terms of adverse environmental, energy, or economic impacts. The net environmental impact is the first analysis performed for each alternative. Both beneficial impacts and adverse impacts should be discussed and qualified/quantified where possible. All air pollutants should be included in the analysis, including air pollutants not currently regulated under the Clean Air Act. Therefore, an analysis of unregulated air pollutants and their potential impact is required as part of the BACT analysis. The direct energy impacts of the control alternatives are estimated in terms of energy consumption (BTUs, barrels of oil, kWh, etc.).

In addition, the impacts of relying on scarce fuels must be considered because of the possibility of a change in availability in subsequent years. Finally, the economic impacts of control alternatives with primary consideration to the cost effectiveness (dollars per ton of pollutant removed) are evaluated for each option. This analysis generally includes an estimate of the capital and annualized costs for each alternative based on vendor quotes and established USEPA cost-estimating procedures addressing both average and incremental cost effectiveness for each alternative.

The following alternative control systems were considered in the BACT analysis for the three combustion turbines with duct burners, the auxiliary boiler, the emergency diesel generator, and the diesel fire pump.

Pollutant	Technique
NO_X	Selective catalytic reduction (SCR) with dry low NO_X combustion (DLN)
SO_2	Very low sulfur fuels
TSP/PM_{10}	Good combustion practices/ design
CO	Oxidation catalyst
	Good combustion practices/ design
VOC	Oxidation catalyst
	Good combustion practices/ design

The only option considered for the cooling towers was drift eliminators and good design.

Control devices similar in efficiency and function were not considered and only those technologies which have been commercially demonstrated and for which manufacturer guarantees are available have been analyzed.

<u>COMBUSTION TURBINES AND DUCT BURNERS</u>

Nitrogen Oxides (NO_X)

Nitrogen Oxides (NO_X) are formed during the fuel combustion process. There are three types of NO_X formations: thermal NO_X, fuel bound NO_X, and prompt NO_X. Thermal NO_X is created by the high temperature reaction in the combustion chamber between atmospheric nitrogen and oxygen. The amount that is formed is a function of time, turbulence, temperature, and fuel to air ratios within the combustion flame zone. Fuel-bound NO_X is created by the gas-phase oxidation of the elemental nitrogen contained within the fuel. Its formation is a function of the fuel nitrogen content and the amount of oxygen in the combustion chamber. Fuel NO_X is temperature-dependent to a lesser degree; at lower temperatures, the fuel bound nitrogen will form N_2 rather than NO_X. The fuel specification for these turbines, natural gas, has inherently low elemental nitrogen, so the effects of fuel NO_X are insignificant in comparison to thermal NO_x.

Prompt NO_X occurs primarily in combustion sources that use fuel rich combustion techniques. The formation of prompt NO_X occurs through several early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. The reactions primarily take place within fuel rich flame zones and are usually negligible when compared to the formation of NO_X by the thermal NO_X process. Combustion turbines generally have high mixing efficiencies with excess air, rich combustion zones rarely exist, and the formation of prompt NO_X is not deemed a significant contributing factor towards NO_X formation.

Since the formation of NO_X is largely dependent on thermal NO_X, several control technologies employ techniques to reduce the precursors of NO_X formation or use catalysts to treat the post combustion emissions. There are three types of emission controls for natural gas-fired turbines. The least effective are wet controls, which use steam or water injected into the combustion zone to reduce the ambient flame temperature, thus controlling NO_X formation. Intermediate are dry controls that use advanced combustor design to suppress NO_X formation. Most effective are post-combustion catalytic controls that selectively or non-selectively reduce NO_X. This project proposes the use of a combination of dry low NO_X (DLN) combustion and selective catalytic reduction (SCR), which represents the most stringent commercially available NO_X control technology. The less effective controls will not be analyzed.

The SCR will be added as a post combustion treatment for NO_X emissions by injecting ammonia (NH_3) into the turbine/ duct burners exhaust stream and upstream from the catalyst unit. The ammonia injected exhaust stream enters and reacts with the catalyst beds to form N_2 and H_2O. At high temperatures, NO_X emissions increase and the reaction becomes counter-productive. Reaction mechanisms involved in the process are very temperature-sensitive and can be used to reduce NO_X only over a narrow temperature window.

Application of an SCR unit can achieve a NO_X emission concentration of 4.5 ppmvd at 15 percent oxygen for combustion turbines of this type. Addition of the duct burners increases the emissions to approximately 10.8 ppmvd at 15% oxygen. The result is a maximum NO_X emission rate of 61 pounds per hour for each turbine at full load with duct burners firing.

As mentioned previously, the side effect of this NO_X control system is ammonia slip. Ammonia slip occurs because the exhaust temperature falls outside the optimum catalyst reaction range or because the catalyst itself becomes prematurely fouled or exceeds its life expectancy. Some ammonia slip will occur regardless of the efficiency of the unit due to the SCR manufacturer’s recommendation to inject NH_3 in amounts slightly above what is stoichiometrically required. Ammonia slip associated with this excess requirement will be designed to not exceed 10 ppm, while continuing to insure that the proposed NO_X emission level is met.

There are potential environmental impacts associated with the SCR system, although they are not significant. Ammonia slip, mentioned previously, will be designed to not exceed 10 ppm through the proper control of ammonia injection while maximizing NO_X reduction. A second potential environmental impact is a negligible amount of ammonia salt precipitation that can be emitted to the atmosphere. Ammonia salt formation is a function of the fuel bound sulfur content and the amount of excess ammonia in the catalyst bed. Sulfur dioxide in the exhaust stream is oxidized by the catalyst to form sulfur trioxide, which then mixes with water vapor to form sulfuric acid. This acid then reacts with the free or unreacted ammonia to form ammonia salts that can agglomerate in the exhaust stream as it cools. The potential for formation of ammonia salts is minimal due to the low sulfur content of natural gas. A third environmental impact is associated with the transportation, handling and storage of aqueous ammonia, which can result in potential spills and evaporation of ammonia into the atmosphere. The overall risk of this occurrence is considered low. There are no environmental impacts associated with the spent catalyst material, because the metal is typically shipped back to the manufacturer for recycling.

A review of the RBLC for combined cycle combustion turbines firing natural gas indicates BACT emission limits ranging from 4 to 6 ppm, based on the application of SCR technology. The application package contains a listing of permitted facilities from the RBLC in Appendix B. A review of RBLC by the DEQ showed a large number of turbines controlled by numerous technologies. While some BACT determinations have been made at levels down to 4 ppm, others have been made at 25 to 30 ppm. A large number have been made in the vicinity of 15 ppm, which is well above the limits proposed by the applicant for this facility. Thus, the applicant's proposal for dry low-NO_X combustion and selective catalytic reduction to achieve NO_x emission limits of 4.5 ppmvd at 15% oxygen when firing the turbine only, and 10.8 ppm when firing the duct burner with the turbine are acceptable as BACT.

Carbon Monoxide (CO)
Combustion turbines and duct burners are designed to combust fuel as completely as possible by incorporating good combustion practices including proper air-to-fuel ratio and a design that adequately accounts for time, temperature, and turbulence conditions within the combustion zone. Two applicable CO control techniques have been identified for combustion turbines. One is catalytic oxidation and the other is based on efficient combustion/ design technology.

Catalytic oxidation of CO is a technically proven control alternative for combustion turbines; however, it has primarily been used to meet specialized requirements such as Lowest Achievable Emission Rate (LAER), typically in non-attainment areas. The installed capital cost associated with catalytic oxidation is $2,021,838 and the annualized cost is $1,137,666 per turbine when firing natural gas. Cost-effectiveness of $12,362 per ton CO removed is considered to be excessive. The energy impact is the result of pressure loss through the catalyst, which reduces the turbine power output. The estimated annual energy impact is $36,059.

The CO emission rate under maximum load conditions with the duct burners on and with appropriate design will be limited to 17.4 ppmvd when firing natural gas. There are no adverse economic, environmental or energy impacts associated with the proposed control alternative. A review of EPA's RBLC database, as found in Appendix C of the application package, indicates that other combustion turbines that utilize natural gas have been issued permits with BACT-based CO emissions in the range of 3 to 60 ppm (based on full load operation). A DEQ review of the RBLC agrees that the proposed emission limits are representative of a top level of emission control. The applicant's proposal of good combustion practices/design is acceptable as BACT for CO emissions from the combustion turbines.

Sulfur Dioxide (SO_2)
Control techniques available to reduce SO_2 emissions include flue gas desulfurization (FGD) systems and the use of low sulfur fuels. A review of the RBLC indicates that while FGD systems

are common on boiler applications, there are no known FGD systems on combustion turbines. Thus, the use of an FGD system is not warranted and an FGD system is rejected as a BACT control alternative.

The proposed facility will utilize natural gas in the turbines and duct burners. Maximum SO_2 emissions are estimated to be 0.006 lb/MMBTU for the turbines with duct burners. The use of very low sulfur fuel has an established record of compliance with applicable regulations. Subpart GG of 40 CFR Part 60 (NSPS) requires either an SO_2 emission limitation of 150 ppm or a maximum fuel content of 0.8 percent by weight. The estimated emissions for these units are significantly less than the NSPS limit. The very low SO_2 emission rate resulting from the use of natural gas is acceptable as BACT for the turbines and duct burners. There are no adverse environmental or energy impacts associated with the proposed control alternative.

Volatile Organic Compounds (VOC)
Catalytic oxidation of VOCs is a technically proven control alternative for combustion turbines. However, it has primarily been used to meet specialized requirements such as LAER, typically in areas that are designated as non-attainment for ozone. Catalytic oxidation can achieve a VOC reduction efficiency of 50 percent for VOC compounds larger than ethane. Since natural gas is comprised of over 92 percent methane, a significantly smaller compound than ethane, the reduction efficiency by this technology when firing natural gas will be much less. However, the cost effectiveness calculation of $33,818 per ton of VOC removed is conservatively based on the 50 percent reduction efficiency. Good combustion practices include proper air-to-fuel ratio and design that adequately accounts for time, temperature, and turbulence conditions within the combustion zone. The annual energy impact is assessed at $53,286. These cost impacts are considered to be prohibitive and catalytic oxidation is rejected as a BACT control alternative.

Almost all of the recent permits listed in the RLBC database indicate that good combustion practices/design is the preferred method of VOC control on combined cycle combustion turbines. The maximum estimated VOC emission concentration is 7 ppmvd at 15 percent oxygen when firing the turbine only and 7.62 when firing both the turbine and duct burners. There are no adverse economic, environmental, or energy impacts associated with good combustion practices/design. Thus, DEQ agrees that good combustion practices/design are acceptable as BACT for control of VOC emissions for the combustion turbines and duct burners.

Total Suspended Particulates/PM_{10}
Total suspended particulates (TSP) and particulate matter less than 10 micrometers will occur from the combustion of natural gas. The EPA's AP-42, Fifth Edition, Supplement D, Section 1, considers such particulate matter to be less than 1 micron, so all emissions are considered as PM_{10}. Particulate emissions from the combustion of natural gas result primarily from inert solids contained in the unburned fuel hydrocarbons, which agglomerate to form particles. PM_{10} emission rates from natural gas combustion are inherently low because of very high combustion efficiencies and the clean burning nature of natural gas. Therefore, the use of natural gas is in and of itself a highly efficient method of controlling emissions. The applicant assumes a maximum PM_{10} emission rate of 0.01 lbs/MMBTU, approximately 132% of the AP-42 factor. Based on the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, there are no BACT

precedents that have included an add-on TSP/PM_{10} control requirement for natural gas-fired combustion turbines. Typically, plume visibility is not an issue for this type of facility as the exhaust plumes are nearly invisible except for the condensation of moisture during periods of low ambient temperature so this choice is protective of any reasonable opacity standard. There are no adverse environmental or energy impacts associated with the proposed control alternative. DEQ agrees that the use of a low ash fuel and efficient combustion is acceptable as BACT for PM_{10} emissions from the combustion turbines and duct burners.

AUXILIARY BOILER

Nitrogen Oxides (NO_X)

The boiler design will incorporate low-NO_X burners for NO_X control, which is common for auxiliary boilers. The estimated NO_X emissions rate is 0.049 lb/MMBTU. No adverse environmental or economic impacts are associated with this NO_X control technology. Due to the intermittent use of this boiler, the use of low-NO_X burners is acceptable as BACT for NO_X control of the auxiliary boiler.

Carbon Monoxide (CO)

Control technologies evaluated for use on the natural gas-fired auxiliary boiler include catalytic oxidation and proper boiler design/good operating practices. The cost of add-on controls on intermittently operated facilities is prohibitive. Controlling boiler-operating conditions can minimize carbon monoxide emissions. This includes proper burner settings, maintenance of burner parts, and sufficient air, residence time, and mixing, for complete combustion. The maximum estimated CO emission rate is 0.082 lb/MMBTU. The proposed BACT will not have any adverse environmental or energy impacts. Boiler design and good operating practices are acceptable as BACT for controlling CO emissions from the auxiliary boiler.

Sulfur Dioxide (SO_2)

Control techniques available to reduce SO_2 emissions include flue gas desulfurization (FGD) systems and the use of low sulfur fuels. A review of the RLBC indicates that while FGD systems are common on boiler applications, they are not common with boilers firing very low sulfur fuels, such as natural gas. FGD systems are not cost effective because the SO_2 emissions are already minimal. The estimated SO_2 emission rate is 0.006 lbs/MMBTU. Thus, the use of an FGD system is not warranted and is rejected as a BACT control alternative.

The use of natural gas is proposed as BACT for the auxiliary boiler. There are no adverse environmental or energy impacts associated with the proposed control alternative. DEQ agrees that the use of commercial quality natural gas is acceptable as BACT.

Volatile Organic Compounds (VOC)

Control technologies evaluated for use on the natural gas-fired auxiliary boiler include catalytic oxidation and proper boiler design and good combustion practices. The cost of add-on controls on intermittently operated facilities is prohibitive. However, optimizing boiler-operating conditions will minimize VOC emissions. Applicant estimates the maximum VOC emission rate to be 0.0054 lbs/MMBTU. Thus, boiler design and good operating practices are proposed as BACT. The proposed BACT will not have any adverse environmental or energy impacts. DEQ agrees that boiler design and good operating practices are acceptable as BACT for controlling VOC emissions from the auxiliary boilers

Total Suspended Particulates/PM_{10}

Since the auxiliary boiler will fire natural gas, the same properties that applied to the combustion turbines will also apply to this application. The maximum estimated TSP/PM_{10} emission rate is 0.0074 lbs/MMBTU. The EPA's RACT/BACT/LAER Clearinghouse (RBLC) database research indicates that there are no BACT precedents for TSP/PM_{10} requiring add-on controls. The discussion under the turbine/duct burner TSP analysis applies here. There are no adverse environmental or energy impacts associated with the proposed control alternative. DEQ agrees that the use of a low ash fuel and efficient combustion is acceptable as BACT for PM_{10} emissions from the auxiliary boiler.

EMERGENCY DIESEL GENERATORS

Nitrogen Oxides (NO_X)

A review of the RBLC indicates that emergency diesel generators have not been required to install additional NO_X controls because of intermittent operation. An uncontrolled NO_X emission of 4.41 lbs/MMBTU for the emergency diesel generator is based on engine design and is proposed as BACT. The proposed BACT has no adverse environmental or energy impacts. DEQ agrees that engine design is acceptable as BACT.

Carbon Monoxide (CO)

Control technologies for CO emissions evaluated for use are catalytic oxidation and proper design to minimize emissions. Because of the intermittent operation and low emissions, add-on controls would be prohibitively expensive. Thus, engine design is proposed as BACT for controlling the CO emissions from the emergency diesel generators to an estimated 0.95 lbs/MMBTU is proposed as BACT. The proposed BACT has no adverse environmental or energy impacts. DEQ agrees that engine design is acceptable as BACT.

Sulfur Dioxide (SO_2)

The only known SO_2 control technique for use on the emergency diesel generators is the use of low sulfur fuel. The use of low sulfur fuel, proposed as BACT, leads to an SO_2 emission limit of 0.29 lbs/MMBTU. There are no adverse environmental or energy impacts associated with this proposed BACT. DEQ agrees that use of low-sulfur fuel is acceptable as BACT.

Volatile Organic Compounds (VOC)

Control technologies for VOCs include catalytic oxidation and proper design to minimize emissions. Because of the intermittent operation and low emissions, add-on controls would be prohibitively expensive. An emission of 0.36 lbs/MMBTU based on engine design is estimated. The proposed BACT will not have any adverse environmental or energy impacts. DEQ agrees that engine design is acceptable as BACT.

Total Suspended Solids/ PM_{10}
These units, like the turbines and auxiliary boiler, emit particulates consisting of ash in the fuel and residual carbon and hydrocarbons caused from incomplete combustion. The applicant's review of RBLC shows that good combustion control and/or good engine design is the most stringent requirement for this application. An emission rate of 0.31 lbs/MMBTU is estimated for this proposed BACT. The proposed BACT will not have any adverse environmental or energy impacts. DEQ agrees that combustion control and good engine design is acceptable as BACT.

DIESEL FIRE PUMP
BACT discussions for the fire pump exactly parallel those for the emergency generators. The following tabulation shows only the emission factors.

Pollutant	Factor (Lb/MMBTU)
Nitrogen Oxides (NO_X)	4.41
Carbon Monoxide (CO)	2.62
Sulfur Dioxide (SO_2)	0.29
Volatile Organic Compounds (VOC)	0.36
Total Suspended Particulates/PM_{10}	0.31

COOLING TOWERS
Cooling tower drift is a source of particulate emission, caused by dissolved and suspended solids inherently contained within the liquid droplets. The water droplets evaporate, allowing the particulates to agglomerate. The particle sizes are mostly in the 20 to 30 micron range, according to a 1984 EPRI report titled "User's Manual: Cooling-Tower-Plume Prediction Code", Section 4, Pg. 4-1. There are no technically feasible alternatives that can be installed on the cooling towers, which specifically reduce particulate emissions; however, cooling towers are typically designed with drift elimination features. The drift eliminators are specially designed baffles that collect and remove condensed water droplets in the air stream. These drift eliminators, according to a review of the EPA's RBLC, can reduce drift to 0.001 percent to 0.004 percent of cooling water flow, which reduces particulate emissions.

The use of such drift eliminators to attain an emission rate of 9.6 lbs/hr of TSP (zero PM_{10}) is proposed as BACT for cooling tower particulate emissions. The proposed BACT has no adverse environmental or energy impacts. DEQ agrees that drift eliminators are acceptable as BACT

B. Air Quality Impacts
The air quality impact analyses were conducted to determine if ambient impacts would result in a radius of impact being defined for the facility for each pollutant. If a radius of impact occurs for a pollutant then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required.

Modeling Methodology
Modeling was conducted using the EPA-approved Industrial Source Complex – Short Term model (ISCST3) to determine if a significant impact area for each pollutant occurred. A Cartesian

receptor grid was used in the modeling analysis. Receptors were modeled at 100-meter intervals along the site property line and extending out to 1.5 kilometers from the sources. Receptor spacing increases to 500 meters between 1.5 and 10 kilometers, and finally to 1,000 meters out to 50 kilometers. Rural coefficients were used for the site because USGS indicated the area was mostly rural for a three-kilometer area around the proposed facility.

A downwash analysis was completed using EPA's BPIP model. The proposed site is located in a rural area and the only buildings that could potentially affect the emissions from the facility are the new turbine enclosures. All other structures on or near the site will not affect downwash based on the H = 1.5L or 5L criteria.

United States Geological Survey maps were obtained and terrain elevations in the fine spacing grid (1.5 kilometers) were interpolated from the maps and entered into the model input files. Terrain heights were not entered in the intermediate and more distant regions because this is a screening step of the process and most of the terrain is simple.

Surface meteorological data from the Tulsa airport were used in conjunction with upper air data from Oklahoma City and Norman to produce the meteorological input files for the modeling analysis. In 1989, the National Weather Service's upper air site was moved from Oklahoma City to Norman, resulting in a three-week loss of data. As such, the 1989 data was not used in this analysis. Upper air data from Oklahoma City was used for 1986 through 1988, and upper air data from Norman was used for 1990 and 1991.

<u>Model Stack Parameters</u>

The turbines will normally be operated in the 70-100% load range except during startup, shutdown, and malfunctions. Emissions from the turbines were calculated at various ambient temperatures between 10° and 95°F at 100% load and at 72°F at 70% load. Emissions were modeled at the condition producing the greatest rates, which is 100% load at 10°F. Emissions from the auxiliary boiler and the cooling towers were included in the model. Emissions from the emergency generators and the diesel fire pump were not modeled since they are relatively low and should operate only intermittently for testing. Stack parameters and emission rates used in the modeling analysis follow.

Stack Parameters

Source	Height (ft)	Diameter (ft)	Temperature (°F)	Exit Velocity (ft/sec)
Turbine[1]	150	18	174	70.90
Cooling Tower[2]	35	33	90	7.6
Auxiliary Boiler	83	2	308	31.3

[1] Each of three turbines

[2] Each of four cells for three towers

Emission Rates

	Rate (lb/hr)		
Pollutant	Each Turbine *	Auxiliary Boiler	Cooling Tower
NO_X	61	1.0	N/A
CO	61	1.72	N/A
SO_2	11.5	0.12	N/A
PM_{10}	20.67	0.15	N/A
TSP **	N/A	N/A	2.40

* With duct burners on

** Emissions from each of four cells for three towers

Based on previous guidance from the ODEQ, an ozone analysis was carried out for the proposed sources based on the method in "VOC/NO_X Point Source Screening Tables" created by Robert Scheffe from the results of reactive plume modeling of the emissions of volatile organic compounds (VOC) and NO_X. Ozone impacts are the result of the reaction of VOC, NO_X, and other chemicals with sunlight and other environmental conditions. No ozone is emitted by the proposed facility directly. Because ozone is not emitted from the proposed sources, the ISCST3 and other dispersion models cannot predict the impacts. The USEPA has developed a series of complicated reactive plume models that estimate the ozone created by a source from the emissions of VOC and NO_X. These models were used by Scheffe to create the tables used in this analysis. The tables used in this analysis and the calculations used to predict the ozone impacts are included as Appendix F of the application package. The ozone impact of all proposed VOC and NO_X emissions associated with the project is estimated at 0.0156 ppm.

Modeling Results

Significance Level Comparisons

Pollutant	Averaging Period	Year	Modeled Maximum Concentrations ($\mu g/m^3$)	Significance Level ($\mu g/m^3$)
SO_2	Annual	1991	0.13	1
	24-hour	1986	0.94	5
	3-hour	1991	4.02	25
Ozone	*		0.0156 ppm*	*
NO_2	Annual	1986	0.82	1
CO	8-hour	1990	14.29	500
	1-hour	1991	36.56	2,000
PM_{10}	Annual	1991	0.23	1
	24-hour	1986	1.14	5

* There is no significance level for ozone. These data are included here for completeness.

The modeling indicates facility emissions will result in ambient concentrations below the significance levels for all standards. Therefore, additional modeling for increment consumption and NAAQS compliance is not required for any pollutant.

C. Evaluation of PSD increment consumption

Based on the analysis in B above, none is required

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

Based on the analysis in B above, none is required

E. Ambient Monitoring

The predicted maximum ground-level concentrations of pollutants by air dispersion models show that the ambient impacts of all pollutants but VOC are below the monitoring exemption levels. Since no simple standard for ozone exists, the ambient impact calculated from the Scheffe tables is added to the design value of the nearest ozone monitoring station, which is No. 174 at Glenpool. Design value is the fourth-highest value recorded over a three-year period and is 0.104 for this station. The sum of the ozone values is 0.104 plus 0.0156 = 0.1196, which is less than the NAAQS value of 0.12 ppm and less than 0.125 ppm, the value at which an exceedance would occur. Note that the Scheffe value is a one-hour value, so the old one-hour NAAQS was used in this calculation. There is no way to calculate an eight-hour value from the Scheffe tables. No pre-construction or post-construction ambient monitoring will be required, although Station 174 could be used for any post-construction monitoring, if necessary. The maximum ambient impacts of the source and the monitoring exemption levels are shown below.

Comparison of Modeled Impacts to Monitoring Exemption Levels

Pollutant	Monitoring Exemption Levels $\mu g/m^3$	Averaging Time	Ambient Impacts $\mu g/m^3$
NO_2	14	annual	0.82
SO_2	13	24-hour	0.94
CO	575	8-hour	14.29
PM_{10}	10	24-hour	1.14
VOC	100 TPY of VOC		205.60 TPY

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

An additional impact analysis is completed based on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the area of potential impact. The additional impact analysis consists of three parts: (1) growth, (2) soils and vegetation impacts, and (3) visibility impairment. Each of these parts is discussed in the sections below.

1) Growth Analysis

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

Approximately 200 trade jobs (i.e., welders, electricians, construction workers, etc.) over a 22-month period will be needed to complete the construction of the project. It is anticipated that the majority of these jobs will be local hires, thus not requiring any additional residential or commercial capacity within the area. Approximately 2 percent will be temporary out-of-town supervisors who will reside in local hotels for the extent of the construction. Approximately 20 full-time positions will be made available for local hiring after construction. Due to the relatively large population of the area, these positions, which are also expected to be local hires, will not cause additional emissions within the area.

2) Ambient Air Quality Impact Analysis

The only source of additional emissions may be from fugitive dust generated from equipment transportation or vehicles during construction. Any long-term air quality impact in the area will result from emissions increases due to operation of the facility. These impacts have been analyzed in preceding sections.

3) Soils And Vegetation Impact Analysis

Tulsa County, Oklahoma has an area of 376,320 acres of which 97 percent is land. The Soil Survey of Tulsa County published by the Soil Conservation Service was used as a basis for the soil types, soil properties, and the suitability of the land. The application package contains a highly detailed analysis of soils and soil associations. The main crops typically grown on the soils identified within the area of impact are tame pasture plants, residential yards and landscaping plantings, small grains, grain sorghum, and soybeans. Some areas are in native grass. No sensitive aspects of the soil and vegetation in this area have been identified. It is anticipated that the potential impacts to the soil and vegetation will be negligible.

G. Evaluation of Class I area impact

A single receptor was placed at the boundary of the closest Class I area, the Upper Buffalo Wilderness Area, AR, approximately 222 kilometers from the proposed facility. The following displays ISCST3 results.

Class I Significance Level Comparisons

Pollutant	Averaging Period	Modeled Maximum Concentrations (ug/m^3)	Significance Level (ug/m^3)
SO_2	Annual	0.0006	0.08
	24-hour	0.030	0.2
	3-hour	0.107	1.0
NO_2	Annual	0.003	0.01
PM_{10}	Annual	0.001	0.16
	24-hour	0.022	0.32

The visual impact of a plume from the project on the Upper Buffalo National Wilderness Area was examined using the Plume Visual Impact Screening Model (VISCREEN). The VISCREEN model was run in the Screening Level I mode. PM emissions (90.95 lb/hr) and NO_x emissions (184 lb/hr) from the proposed project were modeled. The results demonstrate that the maximum impact will be 0.012 versus a significance level of 2.0. Therefore, project will not cause any adverse or significant visual impacts on the Upper Buffalo area.

VI. OKLAHOMA AIR POLLUTION CONTROL RULES

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

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards. In addition, modeled emissions from the proposed facility demonstrate that the facility would not have a significant impact on air quality.

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, 2002, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. These requirements are covered in the "Federal Regulations" section.

OAC 252:100-5 (Registration of Air Contaminant Sources) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Required annual information (Turn-Around Document) shall be provided to Air Quality.

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 that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule
- 0.6 TPY of any one Category A toxic substance
- 1.2 TPY of any one Category B toxic substance
- 6.0 TPY of any one Category C toxic substance

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

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner or operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Part 70/Title V sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.
This subchapter also allows for alternate reporting for certain exceedances that result from technological limitations, per §9-3.1(b)(2). If a demonstration of such limitations is supplied, immediate oral notice may be provided as required by §9-3.1(a), but the written reports may be compiled into a single report to be submitted quarterly.

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

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
Section 19-4 regulates emissions of PM from fuel-burning equipment. Particulate emission limits are based on maximum design heat input rating. Appendix C specifies such PM emission limitations. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Thus, the following are subject to the requirements of this subchapter. The turbines, duct burners, auxiliary boiler, and fuel preheaters shall burn only commercial grade natural gas.

Equipment	**Maximum Heat Input,** (MMBTUH)	**Emission Rate, (lb/MMBTU)**	
		Appendix C	Calculated
Combustion turbines	1,698	0.18	0.01
Duct burners	265	0.28	0.01
Auxiliary boiler	23.6	0.49	0.01
Fuel preheaters	5	0.60	0.01
Emergency generator	8.4	0.60	0.31
Fire pump	1.23	0.60	0.31

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas there is very little possibility of exceeding the opacity standards.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with

the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility has negligible potential to violate this requirement; therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment. For gaseous fuels the limit is 0.2 lb/MMBTU heat input. The applicant assumed a value ten times that provided in AP-42, or 0.006 lb/MMBTU, that is significantly below the Subchapter standard. Using the range of grains of sulfur per 100 dscf in normal Oklahoma gas contracts allows the calculation of maximum emissions to be 0.057 lb/MMBTU, with an annual expected average of 0.0007 lb/MMBTU. Burning only commercial natural gas provides compliance for the turbines and duct burners.
Part 5 also requires opacity and sulfur dioxide monitoring for equipment rated above 250 MMBTUH. Equipment burning gaseous fuel is exempt from the opacity monitor requirement, so the turbines and duct burners do not require such monitors. Equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitor requirement. The maximum permissible amount of sulfur in commercial quality gas is more than an order of magnitude below 0.1 weight percent, so the turbines and duct burners do not require such monitors.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.2 lb of NOx per MMBTU, three-hour average. The maximum one-hour emission rate for the turbines, based on the BACT requirement of 4.5 ppmvd is 0.018 lb/MMBTU, which is in compliance. If the rate is based on the combined exhaust of the combustion turbines and HRSGs, the BACT requirement of 10.8 ppm converts to 0.031 lb/MMBTU, which is still in compliance.

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

OAC 252:100-37 (Volatile Organic Compounds) [Part 7 Applicable]
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 vapor pressure of diesel is less than 1.5 psia, therefore, Part 3 does not apply.
Part 5 limits the VOC content of coating used in coating lines or operations. This facility will not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion. Combustion control is a BACT requirement to minimize emissions.

OAC 252:100-39 (VOC in Nonattainment and Former Nonattainment Areas) [Applicable]
This subchapter imposes additional conditions beyond those of Subchapter 37 on emissions of organic materials from new and existing facilities in Tulsa and Oklahoma Counties.
Part 3 covers Petroleum Refinery Operations, of which there are none.
Part 5 applies to EFR tanks, of which there are none.
Part 7 covers Specific Operations. Section 39-41 concerns the storage of VOC in tanks with storage capacity greater than 400 gallons. The low vapor pressure of diesel exempts the storage tanks from this section per §39-4.

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 31, 2002, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, J, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, LL, KK, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, CCCC, GGGG, HHHH, NNNN, SSSS, TTTT, UUUU, VVVV, and XXXX are hereby adopted by reference as they exist on July 31, 2002. These standards apply to both existing and new sources of HAPs. These requirements are covered in the "Federal Regulations" section.
Part 5 is a **state-only** requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category "A" pollutant above de minimis levels must perform a BACT analysis, and if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant that exceed the de minimis level do not cause or contribute to a violation of the maximum acceptable ambient concentration (MAAC). A BACT analysis was performed for the project and proper operation of combustion equipment constitutes BACT for the Category A toxics. Four chemicals were shown in the Emission Calculations Section to have emissions in excess of their respective Category thresholds. Applicant used ISCST3 to calculate a ground level concentration (GLC) for each as shown in the following table. The GLCs are significantly less than their respective MAACs.

Chemical	TPY	GLC ($\mu g/m^3$)	MAAC ($\mu g/m^3$)
Acetaldehyde	1.032	0.01	3,600
Ammonia	293.022	1.76	1,742
Formaldehyde	2.72	0.02	12
Propylene oxide	0.748	<.01	500

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 Air Quality.

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

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

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

VII. FEDERAL REGULATIONS

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

NSPS, 40 CFR Part 60 [Subparts GG, Da, and Dc Applicable]
Subpart GG affects stationary gas turbines with a heat input at peak load of greater than or equal to 10.7 gigajoules per hour (10 MMBTUH) based on the lower heating value of the fuel and that commenced construction, reconstruction, or modification after October 3, 1977. The new turbines have LHV heat input capacities at peak load of 1,530 MMBTUH and are subject. The turbines are governed by 40 CFR 60.332(b) and must satisfy the NO_X standard set forth in §60.332(a)(1). As applied to these turbines, the formula yields an upper limit of 171 ppmvd. For NO_X emissions, the BACT requirements of 4.5 ppmvd for the turbine alone or 10.8 ppmvd for the turbine with duct burners are more stringent than Subpart GG and are applicable. Testing fuel for nitrogen content was addressed in a letter dated May 17, 1996 from EPA Region 6. Monitoring of fuel nitrogen content shall not be required when pipeline-quality natural gas is the only fuel fired in the turbine.
Sulfur dioxide standards specify that no fuel shall be used which exceeds 0.8% by weight sulfur nor shall exhaust gases contain in excess of 150 ppm SO_2. For fuel supplies without intermediate bulk storage, the owner or operator shall either monitor the fuel nitrogen and sulfur content daily or develop custom schedules of fuel analysis based on the characteristics of the fuel supply; these custom schedules must be approved by the Administrator before they can be used for compliance with monitoring requirements. The EPA Region 6 letter referenced above also states that when pipeline-quality natural gas is used exclusively, acceptable monitoring for sulfur is a quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly “stain tube” analysis.
Finally, the subpart allows custom fuel monitoring schedules, and the facility has received approval from EPA Region 6 for such a schedule. Under this plan, hydrogen sulfide must not exceed 1.0 grain/100 SCF and total sulfur may not exceed the $0.8\%_W$ standard. Testing for each will occur at the same time. The schedule begins with testing for four consecutive weeks, followed by monthly testing, followed by semiannual testing in the first and third quarters of

each year. Failure of any these tests requires that the schedule be re-examined for possible modification, and testing shall convert to weekly during any such period of re-examination. Testing done to date has shown numbers below the threshold values.

Subpart Da affects electric steam generating units with a design capacity greater than 250 MMBTUH constructed after September 18, 1978. Combined cycle gas turbines with such capacity are affected sources only if fuel combustion in the heat recovery unit exceeds the 250 MMBTUH level. Since duct burners in the HRSGs add 265 MMBTUH, they are subject to Da. Emission standards, monitoring requirements, and performance testing are described for PM (opacity), SO_2 and NO_X.

The §60.42a standard for PM is 0.03 lb/MMBTU. Maximum PM anticipated from HRSG emissions is 0.012 lb/MMBTU. This section also contains an opacity standard of no greater than 20% (six-minute average) except for one six-minute period per hour of no more than 27%. Sources using exclusively gaseous fuels are exempt from continuous monitoring of opacity per §60.47a(a).

The §60.43a standard for SO_2 is 1.20 lb/MMBTU. Maximum SO_2 anticipated from HRSG emissions is 0.006 lb/MMBTU. Sources using exclusively gaseous fuels are exempt from continuous monitoring of SO_2 per §60.47a(b).

The §60.44a standard for NO_X is 0.20 lb/MMBTU. Maximum NO_X anticipated from HRSG emissions is 0.10 lb/MMBTU. Continuous monitoring of NO_X is required per §60.47a(c).

Further discussion covers supporting tests, defines the Reference Methods to be used and gives reporting requirements. These points will be outlined in the Specific Conditions.

Subpart Db affects steam generating units with a design capacity greater than 100 MMBTUH heat input and which commenced construction, modification or reconstruction after June 19, 1984. Per 40 CFR 60.40b(e), steam units meeting the applicability requirements under Subpart Da are not subject to this Subpart.

Subpart Dc affects industrial-commercial-institutional steam generating units with a design capacity between 10 and 100 MMBTUH heat input and which commenced construction or modification after June 9, 1989, so the 23.6 MMBTUH auxiliary boiler is an affected source. Particulate and SO_2 standards are not set for gas-fired units. The only applicable standards are initial notification (§60.48c(a)) and a requirement to keep records of the fuels used (§60.48c(g)).

NESHAP, 40 CFR Part 61 [Not Applicable]

There are no emissions of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, radionuclides or vinyl chloride. The facility emits small amounts of mercury and benzene but it is not one of the applicable sources and is, therefore, exempt from this part.

NESHAP, 40 CFR Part 63 [Not Applicable At This Time]

Subpart YYYY (Stationary Combustion Turbines) was proposed on January 14, 2003. The MACT affects only turbines located at facilities that are major sources of HAP. As discussed in the emissions section above, this facility is not major for HAP. If the facility is modified in such a manner that it becomes major for HAPs, the turbines are required to be in compliance with Subpart YYYY on the date the facility becomes major. Air Quality reserves the right to reopen this permit if this or any other standard becomes applicable.

CAM, 40 CFR Part 64 [Applicable]
Compliance Assurance Monitoring (CAM) as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria.

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

The turbines are designed with dry low-NO_X (DLN) burners to control emissions oxides of nitrogen. They also have selective catalytic reduction (SCR) as an add-on control for NO_X. While DLN is not an active device, SCR is. NO_X is a pollutant subject to limits and standards and uncontrolled emissions would easily exceed 100 TPY, so the turbines appear to be subject to CAM with respect to NO_X. However, the turbines are exempt per 64.2(b)(i), because Subpart GG is an emission standard proposed by the Administrator after November 15, 1990, pursuant to section 111 or 112 of the Act.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
The turbines burn natural gas only. Natural gas is a listed substance in CAAA 90 Section 112(r). However, this substance is not stored on site. The small quantity that is in the pipelines on the facility is much less than the 10,000-pound threshold and, therefore, is excluded from all requirements including the Risk Management Plan (RMP). The facility stores aqueous ammonia (30%) in three 3,000-gallon tanks. However, the tanks serve separate systems and are not manifolded together. Since the rupture of one tank would not cause the rupture of the other tanks, each tank is considered a separate "process" by EPA definitions. Aqueous ammonia has a density of approximately 0.7 gm/ml (5.842 lb/gal). Therefore, one tank will contain 17,526 pounds, which is less than the threshold amount (20,000 pounds) for this substance.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
This facility is an affected source since it commenced 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 this requirement was for the benefit of the regulating agency (Oklahoma DEQ), which can waive this requirement and has done so. The facility has submitted its application.

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

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

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

Stratospheric Ozone Protection, 40 CFR Part 82 [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.

VII. COMPLIANCE

Inspection
Herb Neumann, ROAT permit writer, performed an initial operating permit inspection on May 15, 2003. Linne Rollins, Compliance Supervisor for the facility, and Tracy Patterson, Air Quality Manager for Cogentrix presented data and provided a tour of the facility. Current 12-month fuel consumption for operating units is compared with quantities authorized by the permit in the following table, in units of MMMBTU. The period covered is 5/1/02 through 4/30/03.

Unit	Actual	Authorized
CT 1	4,748.9	14,874.5
CT 2	4,358.7	14,874.5
CT 3	4,746.0	14,874.5
DB 1	280.7	2,321.4
DB 2	370.0	2,321.4
DB 3	325.2	2,321.4

Annual operating hours for various units are compared with hours authorized by the permit in the following table. The period covered is 5/1/02 through 4/30/03.

Unit	Actual hours	Authorized hours
Auxiliary boiler	1,892	3,000
Emergency generator	11.4	500
Fire pump	22.1	500

Auxiliary boiler fuel has been recorded in pounds, rather than MCF or MMBTU, but this appears to be acceptable for NSPS recordkeeping requirements.

Fuel total sulfur analyses taken for the first four weeks of monitoring under the custom fuel monitoring schedule showed a maximum concentration of 5.6 ppm, and the maximum reading taken in the ensuing 15 months has been 5.2 ppm, with a 15-month average near 4.3 ppm. The Subpart GG standard of $0.8\%_W$ is equivalent to 8,000 ppm. Hydrogen sulfide concentrations were also recorded in ppm, with maxima of 1.37 and 1.61 over the same comparison periods, with an average near 1.15. None of these values exceeds even 50% of the 0.1 grains/100 CF standard. The facility has been requested to maintain these records in the same units as described for each standard in Subpart GG.

The facility made timely application for an acid rain permit.

Testing

Initial performance testing occurred February 5–9, 2002. Because of some difficulty in maintaining full loads during the original test period, additional full-load testing was performed on May 14, 2002 for Unit #1, on April 30, 2002 for Unit #2, and on April 19, 2002 for Unit #3. Testing covered compliance with NSPS and permit limits, as tabulated below. The testing run at 70% load on the turbine and without the duct burners is labeled "70%" and the testing run at full load on the turbines with the duct burners operating is labeled "full". Retest results are further identified with an asterisk (*). Note that the full-load heat inputs are 98.8%, 97.1%, and 98.1% respectively of Units #1, #2, and #3 capacities.

UNIT #1 (1,940 MMBTUH actual average at full load)

Pollutant	Units	Average @ 70%	Average @ full	Limit
PM	Lb/hr		5.72	23.3
	Lb/MMBTU		0.002*	0.03
CO	ppmdv	0.28	1.1*	17.40
	Lb/hr	0.89	5.2*	61.00
Sulfur	ppmdv	4.310		
SO_2	TPY		6.12	52.51

UNIT #2 (1,907 MMBTUH actual average at full load)

Pollutant	Units	Average @ 70%	Average @ full	Limit
PM	Lb/hr		6.64	23.3
	Lb/MMBTU		0.0007*	0.03
CO	ppmdv	0.38	1.7*	17.40
	Lb/hr	1.25	5.1*	61.00
Sulfur	ppmdv	4.310		
SO_2	TPY		6.01	52.51

UNIT #3 (1,926 MMBTUH actual average at full load)

Pollutant	Units	Average @ 70%	Average @ full	Limit
PM	Lb/hr		3.76	23.3
	Lb/MMBTU		0.003*	0.03
CO	ppmdv	0.45	0.9*	17.40
	Lb/hr	1.27	2.8*	61.00
Sulfur	ppmdv	4.310		
SO_2	TPY		6.10	52.51

Initial certification RATA testing for NO_X CEMS was performed on December 27, 2001 for Unit #1, on January 10, 2002 for Unit #2, and on February 4, 2002 for Unit #3. All Units were certified, and annual testing was performed for all units in December 2002.

Tier Classification And Public Review

This application has been classified as **Tier I** based on the request for a Part 70 Operating Permit. The basis for this determination is that it is an initial operating permit for a new major source that was permitted through the Tier III process, thus not requiring further public review.

The applicant published the "Notice of Filing a Tier III Application" for the construction permit in *The Jenks Journal* on February 25, 1999, published notice of the draft permit in the same venue on June 10, 1999, and published notice of the proposed permit in *The Tulsa World* on July 12, 1999. Detailed information about the construction public review process may be found in the Memorandum associated with that permit. The current permit effort will be treated as a "proposed" permit and sent to EPA for a 45-day review period. Information on all permit actions with respect to this Part 70 permit is available for review by the public on the Air Quality section of the DEQ web page at http://www.deq.state.ok.us.

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

Fee Paid

Initial Part 70 permit fee of $2,000.

VIII. SUMMARY

The applicant has demonstrated compliance with applicable state and federal ambient air quality standards and air pollution control rules and regulations. There are no active Air Quality compliance or enforcement issues that would affect the issuance of this permit. Issuance of the Part 70 operating permit is recommended.

PERMIT TO OPERATE
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Cogentrix Energy, Inc.
Green Country Energy, LLC **Permit Number 99-010-TV**
Gas Turbine Electric Power Plant

The permittee is authorized to operate in conformity with the specifications submitted to Air Quality on August 2, 2002. The Evaluation Memorandum dated July 28, 2003, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Continuing 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)]

	Each of 3 Combustion Turbines, including Duct Burners			
Pollutant	lb/hr	TPY	ppmvd*	lb/MMBTU
NO_X	61.00	267.18	10.8	
CO	61.00	267.18	17.4	
SO_2		52.51		0.006
VOC	15.60	68.33		
PM_{10}	20.67	90.53		
H_2SO_4	2.14	0.28		

* NO_X and CO concentrations are parts per million by volume, dry basis, corrected to 15% oxygen, hourly average.

Limits for toxic emissions subject to OAC 252:100-41 are shown below. These authorized levels are predicated upon maximum operating conditions as listed in Specific Condition 1 and use of AP-42 emission factors for all but formaldehyde, which uses California Air Resources Board figures. Toxics not listed shall not exceed their respective *de minimis* thresholds.

Toxic	TPY
Acetaldehyde	1.03
Ammonia	293.02
Formaldehyde	2.72
Propylene oxide	0.75

2. Compliance with the authorized emission limits of Specific Condition No. 1 shall be demonstrated by fuel usage and initial performance testing designed to satisfy the requirements of Federal NSPS and to confirm the manufacturer-guaranteed emission factors. Use of only

commercial-grade natural gas is limited to 14,874,480 MMBTU per year at each combustion turbine and 2,321,400 MMBTU per year at each HRSG set of duct burners.

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

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

4. Upon issuance of an operating permit, the permittee shall be authorized to operate the turbines and HRSGs 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 generator and emergency fire pump shall each be limited to 500 hours of operation per 12-month rolling period to preserve insignificant status. [OAC 252:100-8]

5. The permittee shall satisfy the emission limitations stated in Specific Condition No. 1, as well as the BACT requirements, by the following means.

a. Each HRSG shall contain a properly operated and maintained SCR.
b. Each combustion turbine shall have dry low-NO_X burners.

6. The fire pump and emergency generator shall be fitted with non-resettable hour-meters.

7. The turbines are subject to federal New Source Performance Standards, 40 CFR 60, Subpart GG, and shall comply with all applicable requirements. [OAC 252:100-4, 40 CFR 60.330 et seq]

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

8. The duct burners are subject to federal New Source Performance Standards, 40 CFR 60, Subpart Da, and shall comply with all applicable requirements. [OAC 252:100-4, 40 CFR 60.40a et seq]

a.	60.42a:	Standard for particulate matter
b.	60.43a(b):	Standard for sulfur dioxide
c.	60.44a(a):	Standard for nitrogen oxides
d.	60.47a:	Emission monitoring
e.	60.48a:	Compliance determination procedures and methods
f.	60.49a:	Reporting requirements

9. The auxiliary boiler is subject to federal New Source Performance Standards, 40 CFR 60, Subpart Dc, and shall comply with all applicable requirements. The permittee shall maintain a record of the amount of natural gas burned in the auxiliary boiler.

[OAC 252:100-4, 40 CFR 60.40c et seq]

10. 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. The facility is subject to a custom fuel monitoring schedule, approved by EPA Region 6, for total sulfur and hydrogen sulfide. Under this plan, hydrogen sulfide must not exceed 1.0 grain/100 SCF and total sulfur may not exceed the 0.8%$_W$ standard. Testing for each will occur at the same time. The schedule begins with testing for four consecutive weeks, followed by monthly testing, followed by semiannual testing in the first and third quarters of each year. Failure of any these tests requires that the schedule be re-examined for possible modification, and testing shall convert to weekly during any such period of re-examination. [OAC 252:100-4, 40 CFR 60.335(d)]

11. The permittee shall comply with all acid rain control permitting requirements and for SO_2 and NOx emissions allowances and continuous emissions monitoring and reporting.
[40 CFR 72, 73, & 75]

12. NO_X and CO concentrations listed in Specific Condition No. 1 shall not be exceeded except during periods of start-up, shutdown or maintenance operations. Such periods shall not exceed four hours per occurrence.

13. The permittee shall maintain records as listed below. These records shall be maintained on site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-45]

a. CEMS data required by the Acid Rain program.
b. Operating hours for the auxiliary boiler (monthly and rolling 12-months).
c. Operating hours for the emergency generator and fire pump (rolling 12-months).
d. Fuel consumption for each turbine and for each HRSG (monthly and rolling 12-months).
e. Total sulfur content and hydrogen sulfide content of natural gas (as required by the custom fuel monitoring schedule described in SC #10).

14. This permit supersedes all other permits issued for this facility, and they are now null and void.

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

a)	OAC 252:100-4	New Source Performance Standards
b)	OAC 252:100-11	Alternative Emissions Reduction
c)	OAC 252:100-15	Mobile Sources
d)	OAC 252:100-17	Incinerators
e)	OAC 252:100-23	Cotton Gins
f)	OAC 252:100-24	Grain Elevators
g)	OAC 252:100-35	Carbon Monoxide
h)	OAC 252:100-47	Municipal Solid Waste Landfills

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. Details covering this certification may be found in Section IV of the Standard Conditions of this permit, and the format of such certification is available in the Air Quality section of the DEQ website.

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

PART 70 PERMIT

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

Issuance Date: ______________________ Permit Number: 99-010-TV

Cogentrix, having complied with the requirements of the law, is hereby granted permission to operate three gas-fired combustion turbines and three heat recovery steam generators to power steam turbines, with ancillary equipment, all for electrical generation at the Green Country Energy, LLC facility, 12307 S. Florence Avenue, Jenks, Tulsa County, Oklahoma,

subject to the following conditions, attached:

[X] Standard Conditions dated October 17, 2001
[X] Specific Conditions

This permit shall expire five (5) years from the issuance date, except as Authorized under Section VIII of the Standard Conditions.

_______________________________ Chief Engineer, Air Quality Division

Rick Shackelford, Plant Manager
Green Country Energy, LLC
12307 S. Florence Avenue
Jenks, OK 74037

Re: Part 70 Operating Permit No. **99-010-TV**
Combustion Turbines and HRSGs
Green Country Energy LLC, Jenks, OK

Dear Mr. Shackelford:

Enclosed is the permit authorizing operation of the referenced facility. Please note that this permit is issued subject to certain standard and specific conditions that are attached.

Thank you for your cooperation in this matter. If we may be of further service, please contact our office at (918) 293-1600, or by mail at DEQ Regional Office at Tulsa, 3105 E. Skelly Drive, Suite 200, Tulsa, OK, 74105-6370.

Sincerely,

Herb Neumann
AIR QUALITY DIVISION

Encl.