OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **August 14, 2001**

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

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

THROUGH: Peer Review

FROM: Xiaodan Sun, P.E., Existing Source Permits Unit

SUBJECT: Evaluation of Permit Application No. **2000-115-C(PSD)**
Smith Cogeneration Oklahoma, Inc.
Smith Pocola Energy Project
Section 34, T10N, R27E
LeFlore County, Oklahoma
Directions: Go North on Highway 271 and exit north on Route 112. Turn east on Old Texas Road (approximately ¼ mile from Highway 27) and the Property is located on your left after crossing the rail road tracks.

SECTION I. INTRODUCTION

Smith Cogeneration Oklahoma, Inc. submitted an application for a construction permit on May 7, 2000 and supplemental information on August 18, 2000, December 15, 2000, March 6, 2001, March 29, 2001, April 2, 2001 and April 30, 2001. The proposed facility (SIC Code 4911) will consist of four gas-fired combustion turbines with heat recovery steam generators (HRSGs) producing a nominal total of 1,200 MW. Since the facility will have emissions in excess of Prevention of Significant Deterioration (PSD) threshold levels (100 TPY), the application has been determined to require Tier III public review.

SECTION II. FACILITY DESCRIPTION

The proposed project will include four 171.5 MW natural gas-fired combustion turbines (GE Frame 7FA or equivalent) with four 576.6 MMBtu/hr duct burners operating in combined-cycle mode with four heat recovery steam generators (HRSGs) and two common steam turbine generators. In addition, the facility will include two cooling towers, a fuel gas system, two auxiliary 48 MMBtu/hr natural gas-fired boilers, an 1,100 KW emergency diesel generator, a 250-hp emergency diesel fire pump engine, and two diesel storage tanks.

In combined cycle operation, exhaust gas exiting the combustion turbine at approximately 1,100 °F is ducted to a HRSG where steam is produced to generate additional electricity in a steam turbine generator.

The gas turbines will be GE Model Frame 7FA (or equivalent), each with a nominal output of 171.14 MWe at ISO conditions (59 degrees Fahrenheit and 60% relative humidity), with a higher heat value (HHV) input of 1,877 MMBTUH. The turbines will use dry low-NO_x combustors. Other than startup, shutdown, and malfunction, both combustion turbines will be operated at above 50 percent rated turbine load to assure operations in the "pre-mix" mode. Pre-mix is the operating mode for the burner which optimizes combustion efficiency and produces the lowest NO_X emissions. Each gas turbine operates 8,760 hours per year.

Four supplementally fired, three-pressure HRSG systems extract heat from the exhaust of each turbine. Exhaust gas enters the HRSGs at approximately 1,100 °F and is ultimately cooled to approximately 200 °F by the time it leaves the HRSG exhaust stack. The heat recovered is used in the combined-cycle plant for steam generation and feed water heating. Each HRSG can be supplementally fired by a duct burner rated at 576.6 MMBtu/hr. The duct burner raises the temperature of turbine exhaust gas entering the HRSG to approximately 1,600 °F. Each duct burner operates 8,760 hours per year.

Two common steam turbines receive steam from HRSG at various pressures and each turbine produces approximately 300 MW of electrical power.

Cooling towers will be integral to operation of the facility. The majority of circulating cooling water from the tower is used directly in the surface condenser absorbing heat rejected from the combined-cycle. Cooling water is also required for auxiliary cooling of other plant equipment. The auxiliary cooling water system is a closed loop system in which cooling water from the tower is not mixed with the auxiliary coolant (usually a glycol/water mixture).

Two natural gas-fired auxiliary boilers, rated at 48 MMBtu/hr each, supply auxiliary steam for the facility. They are designed to maintain steam turbine shaft seals and condenser vacuum as well as an elevated temperature within the steam turbine while the gas turbines are off line. By maintaining steam turbine seals and metal temperatures as high as possible, the subsequent plant start up time is minimized.

The 1,100 KW emergency diesel generator will operate less than 500 hours per year. The 250-hp diesel engine will be operated as an emergency fire pump engine and will operate less than 500 hours per year. Each engine is equipped with a 250-gallon diesel storage tank.

SECTION III. 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 emergency generator and diesel fire pump. Each HRSG stack exhausts combustion emissions from its duct burner and related turbine. Very low emissions of VOC are expected from the diesel storage tanks.

Criteria Air Pollutants

The following table shows emissions based on best available data. The emission information is provided by GE for the gas turbines and by Coen for the duct burners. Emission factors for the turbines for NO_x, SO_2, PM_{10}, VOC, and CO are based on manufacturer's guarantees. Emissions of SO_2 are based on 2 grains of sulfur per 100 SCF gas fuel. Emissions of lead were estimated using the emission factor given in AP-42 (3/98) Tables 1.4-2. The heating value of natural gas is taken to be 1,020 BTU/SCF.

The turbine manufacturer's data for NO_x, CO, VOC, SO_2, and PM_{10}, and are based on multiple operating scenarios. The first division is by temperature, including 12°F, 36°F, 59°F (average annual ambient), 75°F, 93°F and 102°F. The second division is by load, including 50%, 75% and 100%. Emission rates (lb/hr) for each pollutant are provided by turbine manufacturer. Emission factors (lb/MMBTU) are provided by duct burner manufacturer at maximum heat input, 70% and 6% of maximum heat input. Maximum emissions for each pollutant occur at 12°F and 100% load of turbine with duct burner fired at its maximum heat input rate except VOC emissions. The maximum VOC emissions occur at 12°F and 100% load of turbine with duct burner fired at 70% of its maximum heat input rate (403.62 MMBTU/hr). The maximum emissions are potential to emit from the turbines and duct burners and are listed in the following table.

	Gas Turbine (each)		Duct burner (each)			Four Unit Totals	
Pollutant	lb/hr	TPY	lb/MMBTU	lb/hr	TPY	lb/hr	TPY
NO_x	63.00	275.94	0.080	46.13	202.04	436.52	1911.92
CO	31.00	135.78	0.055	31.71	138.9	250.84	1098.72
VOC	3.0	13.14	0.035	14.13	61.87	68.52	300.04
SO_2	10.59	46.41	0.0056	3.25	14.25	55.36	242.64
PM_{10}	9.0	39.42	0.010	5.77	25.27	59.08	258.77
Lead	0.00085	0.0037	0.0000005	).000283	0.00124	0.00445	0.0195

Emissions from the auxiliary boilers are calculated using factors from AP-42 (7/98), Tables 1.4-1 & 2 except for SO_2, where the facility again uses an estimate of 2 grains of sulfur per 100 SCF. There are two auxiliary boilers which are rated at 48 MMBtu/hr each and emissions are based on continuous operation (8,760 hours per year). The heating value of the gas is taken to be 1,020 BTU/SCF.

Auxiliary Boilers (Combined)		
	Emissions	
Pollutant	Lb/hr	TPY
NO_X	9.41	41.22
CO	7.91	34.64

SO_2	0.57	2.47
VOC	0.52	2.27
PM	0.72	3.13
Lead	0.00005	0.0002

Emissions from the emergency diesel generator are calculated using factors from AP-42 (10/96), Table 3.4-1 for uncontrolled diesel industrial engines greater than 600 bhp. The generator is rated at 1,100 kW and is limited to 500 operating hours per year. Emissions from the associated 250-gallon diesel storage tank are negligible.

Emergency Diesel Generator		
	Emissions	
Pollutant	Lb/hr	TPY
NO_X	35.39	8.85
CO	8.11	2.03
SO_2	5.90	1.47
VOC	1.04	0.26
PM	1.03	0.26
Lead	Neg.	Neg.

* based on a maximum sulfur content of 0.5% sulfur

Emissions from the diesel fire pump engine are calculated using factors from AP-42 (10/96), Table 3.3-1 for uncontrolled diesel industrial engines less than 600 bhp. The diesel fire pump engine is rated at 250 HP and is limited to 500 operating hours per year. Emissions from the associated 250-gallon diesel storage tank are negligible.

Diesel Fire Pump Engine		
	Emissions	
Pollutant	Lb/hr	TPY
NO_X	7.75	1.94
CO	1.67	0.42
SO_2	0.51	0.13
VOC	0.63	0.16
PM	0.55	0.14
Lead	Neg.	Neg.

* based on a maximum sulfur content of 0.5% sulfur

Emissions from the cooling tower were calculated assuming a drift ratio of 0.001% and total dissolved solids (TDS) of 8,000 ppm. The capacity of cooling tower is 176,000 gallon/min. Each cooling tower yields 7.03 lb/hr or 30.81 TPY of particulate matter.

Total Facility Criteria Pollutant Emissions

Equipment	NO_X		CO		VOC		SO_2		PM_{10}		Lead	
	Lb/hr	TPY	Lb/hr	TPY	Lb/hr	TPY	Lb/hr	TPY	Lb/hr	TPY	Lb/hr	TPY

Gas Turbines (4)	252.0	1103.76	124.0	543.12	12.0	52.56	42.36	185.64	36.00	157.68	0.0034	0.0148
Duct Burners (4)	184.52	808.16	126.84	5556	56.52	247.48	13.00	56.94	23.08	101.09	0.0011	0.005
Auxiliary Boilers (2)	9.41	41.22	7.91	34.64	0.52	2.27	0.57	2.47	0.72	3.13	0.00005	0.0002
Generator	35.39	8.85	8.11	2.03	1.04	0.26	5.90	1.47	1.03	0.26	Neg.	Neg.
Fire Pump	7.75	1.94	1.67	0.42	0.63	0.16	0.51	0.13	0.55	0.14	Neg.	Neg.
Cooling Towers (2)		--	--	--	--	--	--	--	14.06	61.61	--	--
Total	489.07	1963.9	268.5	1135.8	70.71	302.73	62.34	246.71	75.44	323.92	0.005	0.020

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

HAP and TAC emissions are shown in the following table and are based on AP-42 (4/00), Table 3.1-3 for the turbines, and AP-42 (7/98), Table 1.4-3 and Table 1.4-4 for duct burners and auxiliary boilers. Estimates shown in the table for each emissions unit represent the total emissions (both lb/hr and TPY) from all such units. Total HAP and TAC emissions from the diesel fire engine are estimated based on AP-42 (10/96), Table 3.3-1.
Acid mist emissions are estimated based on following information:

> Gas Turbine: 10% (by weight) of the total SO_2 produced from a combustion turbine is converted to SO_3 (on a one-to-one mole basis) and additional 15% of total SO_2 is converted to SO_3 in duct burner if operating. All SO_3 converts to H_2SO_4.
>
> Duct Burner: 15% of SO_2 produced from the duct burner is converted to SO_3 and all SO_3 converts to H_2SO_4.

HAP and TAC emissions from gas turbines, duct burners and auxiliary boilers are listed in the table on following page.

Pollutants	Cat	Gas Turbines		Duct Burners		Aux. Boilers		Facility Total	
		Lb/hr	TPY	Lb/hr	TPY	Lb/hr	TPY	Lb/hr	TPY
*1,3-Butadiene	A	2.9E-03	1.3E-02					2.9E-03	1.3E-02
*2-Methylnaphthalene	C			5.4E-05	2.4E-04	2.3E-06	9.9E-06	5.7E-05	2.5E-04
Acenapthene	A			4.1E-06	1.8E-05	1.7E-07	7.4E-07	4.2E-06	1.9E-05
Acenaphthylene	A			4.1E-06	1.8E-05	1.7E-07	7.4E-07	4.2E-06	1.9E-05
*Anthracene	A			5.4E-06	2.4E-05	2.3E-07	9.9E-07	5.7E-06	2.5E-05
*Acetaldehyde	B	3.0E-01	1.315					3.0E-01	1.315

*Acrolein	A	4.8E-02	2.1E-01					4.8E-02	0.21
*Arsenic	A			4.5E-04	2.0E-03	1.9E-05	8.2E-05	4.7E-04	2.1E-03
Barium	B			9.9E-03	4.4E-02	4.1E-04	1.8E-03	1.0E-02	4.5E-02
*Benz(a)anthrene	A			7.0E-06	1.8E-05	1.7E-07	7.4E-07	4.2E-06	1.8E-05
*Benzene	A	9.0E-02	3.9E-01	4.8E-03	2.1E-02	1.9E-04	8.7E-04	0.0950	0.416
*Benzo(a)pyrene	A			2.7E-06	1.2E-05	1.1E-07	5.0E-07	2.8E-06	1.2E-05
*Benzo(b)-fluoranthene	A			4.1E-06	1.8E-05	1.7E-07	7.4E-07	4.2E-06	1.9E-05
*Benzo(g,h,I)-perylene	A			2.7E-06	1.2E-05	1.1E-07	5.0E-07	2.8E-06	1.2E-05
*Benzo(k)-fluoranthene	A			4.1E-06	1.8E-05	1.7E-07	7.4E-07	4.2E-06	1.9E-05
*Beryllium	A			2.7E-05	1.2E-04	1.1E-06	5.0E-06	2.8E-05	1.2E-04
*Cadmium	A			2.5E-03	1.1E-02	1.0E-04	4.5E-04	2.6E-03	1.1E-2
*Chromium VI	A			3.2E-03	1.4E-02	1.3E-04	5.8E-04	3.3E-03	1.4E-02
*Chrysene	A			4.1E-06	1.8E-05	1.7E-07	7.4E-07	4.2E-06	1.9E-05
*Cobalt	A			1.9E-04	8.3E-04	7.9E-06	3.5E-05	2.0E-04	8.7E-04
Copper	B			1.9E-03	8.4E-03	8.0E-05	3.5E-04	2.0E-03	8.8E-03
*Dichlorobenzene	B			2.7E-03	1.2E-02	1.1E-04	5.0E-04	2.8E-03	1.2E-02
*Ethylbenzene	C	0.240	1.052					0.240	1.052
*Fluoranthene	C			6.8E-06	3.0E-05	2.8E-07	1.2E-06	7.1E-06	3.1E-05
*Fluorene	B			6.3E-06	2.8E-05	2.6E-07	1.2E-06	6.6E-06	2.9E-05
*Formaldehyde	A	5.33	23.35	0.1696	0.7428	0.0071	0.0309	5.51	24.12
*Hexane	C			4.070	17.83	0.169	0.742	4.240	18.57
*Indeno (1,2,3-cd)-pyrene	A			4.1E-06	1.8E-05	1.7E-07	7.4E-07	4.2E-06	1.9E-05
*Manganese	C			8.6E-04	3.8E-03	3.6E-05	1.6E-04	9.0E-04	3.9E-03
*Mercury	A			5.9E-04	2.6E-03	2.4E-05	1.1E-04	6.1E-04	2.7E-03
Molybdenum	C			2.5E-03	1.1E-02	1.0E-04	4.5E-04	2.6E-03	1.1E-02
*Naphthalene	B	9.8E-03	4.3E-02	1.4E-03	6.0E-03	5.7E-05	2.5E-04	1.1E-02	4.9E-02
*Nickel	A			4.8E-03	2.1E-02	2.0E-04	8.7E-04	5.0E-03	2.2E-02
Pentane	C			5.879	25.75	0.245	1.072	6.124	26.82
*Phenanthrene	A			3.8E-05	1.7E-04	1.6E-06	7.0E-06	4.0E-05	1.8E-04
*PAH	A	1.6E-02	7.2E-02					1.6E-02	7.2E-02
*Propylene Oxide	A	2.2E-01	0.954					2.2E-01	0.954
*Pyrene	A			1.1E-05	5.0E-05	4.7E-07	2.1E-06	1.2E-05	5.2E-05
*Selenium	C			5.4E-05	2.4E-04	2.3E-06	9.9E-06	5.7E-05	2.5E-04
Sulfuric acid	A	16.2	70.96	3.00	13.14			19.20	84.10
*Toluene	C	0.976	4.275	7.7E-03	3.4E-02	3.0E-04	1.4E-03	0.984	4.310
Vanadium	A			5.2E-03	2.3E-02	2.0E-04	9.0E-04	5.4E-03	2.4E-02
*Xylene	C	0.481	2.105					0.481	2.405
Zinc	C			0.0656	0.2872	0.0027	0.012	0.0683	0.299
Total		23.91	104.74	13.23	57.96	0.43	1.87	37.57	164.6
Total HAPs		7.71	33.78	4.27	18.70	0.18	0.78	12.16	53.26
Total non-HAPs		16.20	70.96	8.97	39.26	0.25	1.09	25.41	111.3

*-HAPs

The de minimis levels set by OAC 252:100-41-43 are 0.57 lb/hr and 0.6 TPY for category A pollutants, 1.1 lb/hr and 1.2 TPY for category B pollutants, and 5.6 lb/hr and 6.0 TPY for category C pollutants. Six pollutants exceeding the de minimis level are acetaldehyde (CAS 75-0-70) formaldehyde (CAS 50-00-0), hexane (CAS 110-54-3), pentane (CAS 109-66-0), propylene oxides (CAS 75-56-9) and sulfuric acid (CAS 7664939). The Screen3 air dispersion model was used to estimate the ambient air concentration. The results are listed below with MAAC standards.

HAPs	MAAC ($\mu g/m^3$)	Estimated 24 hour Ambient Concentration ($\mu g/m^3$)
Acetaldehyde	3600	0.0138
Formaldehyde	12	0.255
Hexane	17,628	0.194
Pentane	35,000	0.282
Propylene Oxides	500	0.0101
Sulfuric Acid	10	0.84

SECTION IV. PSD REVIEW

The emission summary below show the facility will exceed the significance threshold for emissions of PM_{10}, NO_X, CO, SO_2, H_2SO_4, and VOC. The project is subject to full PSD review. Tier III public review, best available control technology (BACT), and ambient air impacts analyses are also required.

Pollutant	NO_X	CO	SO_2	VOC	PM_{10}	H_2SO_4	Lead	Mercury	Beryllium
Emissions (TPY)	1964	1136	246.7	302.7	323.9	84.13	0.02	0.0027	0.0001
Significance (TPY)	40	100	40	40	15	7	0.6	0.1	0.0004
PSD Review	Yes	Yes	yes	Yes	Yes	Yes	No	No	No

Other pollutants for which PSD significance levels are established (asbestos, vinyl chloride, fluorides, H_2S, and TRS) are not expected to be emitted in other than negligible amounts from this type of facility. As the previous table indicates, PSD review is required for emissions of NO_X, CO, VOC, PM_{10}, SO_2 and H_2SO_4 from this project. Sources to be considered are the turbines, HRSGs, auxiliary boilers, emergency diesel generator and diesel fire pump. Each turbine and its associated duct burner is generally considered as a set for this analysis because they operate as a unit. 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 boilers, 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) as well as EPA's NSR and CTC websites, recent DEQ's BACT determinations for similar facilities, and vendor-supplied information. The following criteria are used for searching the EPA's RACT/BACT/LAER Clearinghouse:

a. Sources permitted since 1989 were included.
b. Data from October 2000 download of the RACT/BACT Clearinghouse was used.
c. For gas turbines, only natural gas fired units and sources exceeding 200 MMBtu/hr and/or 100 MW were included. Where possible, aeroderivative turbines were excluded.

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.

a. NO_X BACT Review

1. Combustion Turbines and Duct Burners

NO_X is produced through two mechanisms: thermal NO_X and fuel NO_X. High temperature processes create thermal NO_X where nitrogen and oxygen gases in the air react. Fuel NO_X is created by combustion of nitrogen-containing materials. The following is a list of control technology which were identified for comtrolling NO_X emissions from gas turbines and their effective emission levels.

Technology	Typical Control Range (% Removal)	Typical Emission Level
SCONO$_X$^{TM}	90-95	2-2.5 ppm
XONON$_{TM}$ Flameless Combustion	80-90	3-5 ppm
Selective Catalytic Reduction (SCR) with low-NO_X combustor or SCR with water injection	50-95	2-6 ppm
SCR with water/steam injection or advanced low-NO_X combustor	50-95	6-9 ppm
Low-NO_X combustor and/or aggressive water injection	30-70	9-25 ppm
Water/steam injection or low-NO_X burners	30-70	25-35 ppm

SCONO$_X$^{TM}

<u>Technical Analysis</u>

SCONO$_X$^{TM}, is an emerging catalytic and absorption technology that has shown some promise for turbine applications. Unlike SCR, which requires ammonia injection, this system does not require ammonia as a reagent, and involves parallel catalyst beds that are alternately taken off line through means of mechanical dampers for regeneration.

SCONO$_X$^{TM} uses an oxidation/absorption/regeneration cycle across a catalyst bed to achieve back end reductions of NO_X. SCONO$_X$^{TM} works by simultaneously oxidizing CO to CO_2, NO to NO_2

and then absorbing NO_2. The NO_2 is absorbed into a potassium carbonate catalyst coating as KNO_2 and KNO_3. When a catalyst module begins to become loaded with potassium nitrites and nitrates, it is taken off line and isolated from the flue gas stream with mechanical dampers for regeneration. Once the module has been isolated from the turbine exhaust, four percent hydrogen in an inert gas of nitrogen or steam is introduced. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. Hydrogen reacts with potassium nitrites and nitrates during regeneration to form H_2O and N_2 that is emitted from the stack.

Commercial Availability
ABB Alston Power, as of December 1999, offered SCONO$_X$^{TM}, with performance guarantees, to all owners and operators of natural gas-fired combustion turbines, regardless of size or gas turbine supplier. The system is designed to reduce both CO and NO_x emissions from natural gas-fired power plants to levels below ambient concentrations. CO emissions of 1 ppm and NO_x emissions of 2 ppm are guaranteed by the manufacturer. In addition, the regional administrator of EPA Region I, in a letter dated December 20, 1999, stated that the Region now considers SCONO$_X$^{TM} a technically feasible and commercially available air pollution control technology that is expected to obtain emission levels for criteria pollutants such as NO_x, CO and VOC comparable or superior to previously-applied technologies for large combined cycle turbine applications.

SCONO$_X$^{TM} has been demonstrated successfully on smaller power plants, including a 32 MW combined-cycle General Electric LM2500 gas turbine at the Federal Cogeneration facility, in Los Angeles, California. This facility uses water injection in conjunction with SCONO$_X$^{TM} to achieve a NO_x emissions rate of 0.75 ppm on a 15-minute rolling average. The SCONO$_X$^{TM} technology has also been successfully demonstrated on a 5 MW Solar Turbine Model Taurus 50 at the Genetics Institute in Andover, Massachusetts. The system is reducing NO_x down to 0.5 ppm NO_x, on a one-hour rolling average. The permit for the power plant was originally issued for 2.5 ppm NO_x.

In addition, US Generating was granted a construction permit on May 29, 1999, to use SCONO$_X$^{TM} for one of the 262 MW power islands at its 1,048 MW La Paloma plant near Bakersfield, California. The permit limits emissions to 2.0 ppmvd NO_x (at 15% O_2) on a three-hour average; a target of 1.0 ppmvd NO_x (at 15% O_2) on a 24-hour average.

PG&E Generating has filed an air permit application to use SCONO$_X$^{TM} on its new 510 MW Otay Mesa power plant in San Diego County, California. PG&E's permit application seeks an initial NO_x limit of 2.0 ppm and a target rate of 1.0 ppm. Finally, Sunlaw Cogenerating Partners has filed an application to use SCONO$_X$^{TM} on its 800 MW combined cycle plant in California.

Economic Evaluation
When NO_X is reduced from 12.18 ppm (gas turbine with duct burner firing) to 2 ppm, the cost effectiveness is $13,627 per ton of NO_X removed.

XONON^{TM}

Technical Analysis

While several companies are reported to be working on this technology, it was first introduced commercially by Catalytica, Inc., and is being marketed under the name XONON™. The XONON™ technology replaces traditional flame combustion with flameless catalytic combustion. NO_x control is accomplished through the combustion process using a catalyst to limit the temperature in the combustor below the temperature where NO_x is formed. The XONON™ combustion system consists of four sections: 1) the preburner, for start-up, acceleration of the turbine engine, and adjusting catalyst inlet temperature if needed; 2) the fuel injection and fuel-air mixing system, which achieves a uniform fuel-air mixture to the catalyst; 3) the flameless catalyst module, where a portion of the fuel is combusted flamelessly; and 4) the burnout zone, where the remainder of the fuel is combusted.

Commercial Availability

There is currently one field installation of the XONON™ technology at a municipal power company, Silicon Valley Power, in Santa Clara, California, being used to perform engineering studies of the technology. NO_x emissions are well below 2.5 ppm on the 1.5 MW Kawasaki M1A-13A gas turbine. Catalytica Combustion Systems (manufacturer of XONON™) has a collaborative commercialization agreement with General Electric Power Systems, committing to the development of XONON™. In conjunction with General Electric Power systems, the XONON™ system has been specified to be used with the GE 7FA turbines to be used at the proposed 750 MW natural gas-fired Pastoria Energy Facility, near Bakersfield, California. The project is expected to begin construction in 2001 and enter commercial operations by the summer of 2003. However, because the NO_x emissions limitations of 2.5 ppm have not been demonstrated in practice by a commercial facility, this technology is not considered commercially available at this time.

Economic Analysis

Since cost data is not available and XONON™ combustors are not offered commercially for the turbines in the size range selected for Smith Pocola Energy Project, an economic analysis could not be performed. XONON™ is not an available control technology.

Selective Catalytic Reduction (SCR)

Technical Analysis

SCR systems selectively reduce NO_x by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. NO_x, ammonia, and oxygen react on the surface to form molecular nitrogen (N_2) and water. The catalyst, comprised of parallel plates or honeycomb structures, is installed in the form of rectangular modules, downstream of the gas turbine in simple-cycle configurations, and into the HRSG portion of the gas turbine downstream of the superheater in combined-cycle and cogeneration configurations.

The turbine exhaust gas must contain a minimum amount of oxygen and be within a particular temperature range in order for the selective catalytic reduction system to operate properly. The temperature range is dictated by the catalyst, which is typically made from noble metals, base metal oxides, or zeolite-based material. The typical temperature range for base-metal catalysts is 600 to 800 °F. Keeping the exhaust gas temperature within this range is important. If it drops below 600 °F, the reaction efficiency becomes too low and increased amounts of NO_x and ammonia will be released out the stack. If the reaction temperature becomes too high, the catalyst may begin to decompose. Turbine exhaust gas is generally in excess of 1,000 °F. HRSG cool the exhaust gases before they reach the catalyst by extracting energy from the hot turbine exhaust gases and creating steam for use in other industrial processes or to turn a steam turbine. In simple-cycle power plants where no heat recovery is accomplished, high temperature catalysts (e.g., zeolite) which can operate at temperatures up to 1,100 °F, are an option. Selective catalytic reduction can typically achieve NO_x emission reductions in the range of about 80 to 95 percent.

SCR uses ammonia as a reducing agent in controlling NO_x emissions from gas turbines. The portion of the unreacted ammonia passing through the catalyst and emitted from the stack is called ammonia slip. The ammonia is injected into the exhaust gases prior to passage through the catalyst bed.

<u>Commercial Availability</u>
SCR is the most widely applied post-combustion control technology in turbine applications and is currently accepted as LAER for new facilities located in ozone non-attainment regions. It can reduce NO_x emissions to as low as 4.5 ppmvd for standard combustion turbines without duct burner firing, and as low as 2 - 2.5 ppmvd when combined with lean-premix combustion (again without duct burner firing).

As mentioned previously, SCR uses ammonia as a reducing agent in controlling NO_x emissions from gas turbines. Gas turbines using SCR typically have been limited to 10 ppmvd ammonia slip at 15 percent oxygen. However, levels as low as 2 ppmvd at 15 percent oxygen have been proposed and guaranteed by control equipment vendors. In addition, Massachusetts and Rhode Island have established ammonia slip LAER levels of 2 ppmvd. To date, Massachusetts has permitted at least two large gas turbine power plants using SCR reduction with 2 ppmvd ammonia slip limits. California has recommended that ammonia slip levels below 5 ppmvd at 15 percent oxygen be established in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip.

<u>Economic Analysis</u>
When NO_X is reduced from 15 ppm (gas turbine with duct burner firing) to 3.5 ppm, the cost effectiveness is $9,473 per ton of NO_X removed.

Lean-Premix Technology or Dry-Low NO_X

<u>Technical Analysis</u>
Turbine manufacturers have developed processes that use air as a diluent to reduce combustion flame temperatures, and have achieved reduced NO_x by premixing the fuel and air before they

enter the combustor. This type of process is called lean-premix combustion, and goes by a variety of names, including the Dry-Low NO_x (DLN) process of General Electric, the Dry-Low Emissions (DLE) process of Rolls-Royce and the $SoLoNO_x$ process of Solar Turbines.

Lean premixed designs reduce combustion temperatures, thereby reducing thermal NO_X. In a conventional turbine combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_X emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers thermal NO_X formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment. Lean-premix combustors can achieve emissions of about 9 ppmvd NO_X at 15 percent oxygen (approximately 94 percent control).

To achieve low NO_x emission levels, the mixture of fuel and air introduced into the combustor (e.g., air/fuel ratio) must be maintained near the lean flammability limit of the mixture. Lean-premix combustors are designed to maintain this air/fuel ratio at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emissions that occur as the air/fuel ratio reaches the lean flammability limit, lean-premix combustors switch to diffusion combustion mode at reduced load conditions. This switch to diffusion mode means that the NO_x emissions in this mode are essentially uncontrolled.

<u>Commercial Availability</u>
Lean-premix technology is the most widely applied pre-combustion control technology in natural gas turbine applications. It has been demonstrated to achieve emissions of approximately 9 ppmvd NO_x at 15 percent oxygen.

Steam/Water Injection

<u>Technical Analysis</u>
Higher combustion temperatures result in greater thermodynamic efficiency. In turn, more work is generated by the gas turbine at a lower cost. However, the higher the gas turbine inlet temperature, the more NO_x that is produced. Diluent injection, or wet controls, can be used to reduce NO_x emissions from gas turbines. Diluent injection involves the injection of a small amount of water or steam via a nozzle into the immediate vicinity of the combustor burner flame. NO_x emissions are reduced by instantaneous cooling of combustion temperatures from the injection of water or steam into the combustion zone. The effect of the water or steam injection is to increase the thermal mass by mass dilution and thereby reduce the peak flame temperature in the NO_x forming regions of the combustor. Water injection typically results in a NO_x reduction efficiency of about 70 percent, with emissions below 42 ppmvd NO_x at 15 percent

oxygen. Steam injection has generally been more successful in reducing NO_x emissions and can achieve emissions less than 25 ppmvd NO_x at 15 percent oxygen (approximately 82 percent control).

Commercial Availability
Steam/Water Injection is the technology commonly used to reduce the NO_X emissions in natural gas turbines.

Summary of NO_X BACT for Turbines and Duct Burners

The following table provides information on the emissions, control effectiveness, economics, energy, and environmental impacts associated with control of NO_X. The analysis was performed on a unit (turbine and duct burner) basis.

	Emissions	Economic Impacts			Env. Impacts
Control Technology	NO_X emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Cost Effectiveness ($/tons)	Adverse Impacts (yes/no)
$SCONO_X$™ (2 ppm)	399.5	14,922,733	5,444,139	13,627	Yes
DLN + SCR (3.5 ppm)	366.5	3,476,578	3,471,362	9,473	Yes

$SCONO_X$™ provides the highest level of NO_X reduction. However, $SCONO_X$™ is a very new technology and has yet to be demonstrated for long term commercial operation on large scale combined cycle plants. The catalyst is subject to the same fouling or masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. There is an energy loss from the performance loss due to the pressure drop across the $SCONO_X$™ catalyst – however, this is not likely to be substantial. Due to the relatively high cost per emission reduction of this control technology ($13,627 per ton of NO_X removed), it is ruled out as control option.
The next most effective control technology for NO_X is a combination of DLN combustors and SCR. The adverse environmental impact of SCR is primarily from the emissions of ammonia. There is also a potential for increased particulate emissions from formation of ammonia salts. SCR may also results in the generation of spent vanadium pentoxide catalyst, which is classified as a hazardous waste. In addition, there is an energy loss from the performance loss due to the pressure drop across the SCR catalyst. However, these adverse impacts can be minimized with proper system design and operation. SCR is ruled out as a control operation because the cost is prohibitive ($10,191 per ton of NO_X removed).

The next most effective control technology is DLN combustors. At reduced loads, combustion instability requires that DLN switches to diffusion combustion mode, which means that the NO_X emissions in this mode are essential uncontrolled. However, this can be minimized with proper system design and operation. The DLN combustor is selected as BACT with following limitations:

NO_X: 9 ppmdv @ O_2 (annual average), without duct burners firing
15 ppmvd @ 15% O_2 (annual average), with duct burners firing

2. Auxiliary Boilers

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 0.10 lb/MMBTU. No other more stringent control techniques were identified as available for this emissions unit. In addition, 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, without further analysis.

3. Emergency Diesel Generator and Diesel Fire Pump

An uncontrolled NO_X emission factor of 3.2 lb/MMBtu for emergency diesel generator and 4.41 lbs/MMBTU for the diesel fire pump engine is based on AP-42 and is proposed as BACT. A review of the RBLC indicates that this type of equipment has not been required to install additional NO_X controls because of intermittent operation. The proposed BACT has no adverse environmental or energy impacts. DEQ agrees that engine design and a limitation on hours of operation is acceptable as BACT.

b. CO BACT Review

1. Combustion Turbines and Duct Burners

$SCONO_X^{TM}$
$SCONO_X^{TM}$ reduce CO emissions by oxidizing CO to CO_2. The technical analysis and commercial availability are discussed in previous section. When CO is reduced from 11.51 ppm (gas turbine with duct burner firing) to 1 ppm, the cost effectiveness is $21,706 per ton of CO removed.
Oxidation Catalyst Technology
Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO to CO_2. The technology has been applied to natural gas-fired combustion turbines of all sizes. When CO is reduced from 11.51 ppm (gas turbine with duct burner firing) to 3.4 ppm, the cost effectiveness is $11,413 per ton of CO removed.

Combustion Control
The combustion control is an inherent design feature of the combustion turbines and duct burner. CO is a result of incomplete combustion of fuel. CO control is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control methods, however, also result in increased emissions of NO_X. Conversely, a low NO_X emission rate achieved through flame temperature can result in higher levels of CO emissions. Thus, a compromise is needed to keep the flame temperature reduction se to achieve the lowest NO_X emission rate possible while keeping CO emissions rates at acceptable levels.

Summary of CO BACT for Turbines and Duct Burners

The following table provides information on the emissions, control effectiveness, economics, energy, and environmental impacts associated with control of NO_X. The analysis was performed on a unit (turbine and duct burner) basis.

	Emissions	Economic Impacts			Env. Impacts
Control Technology	CO emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Cost Effectiveness ($/tons)	Adverse Impacts (yes/no)
SCONO$_X$™ (1 ppm)	251	14,922,733	5,444,139	21,706	Yes
CO Catalyst (3.4 ppm)	194	1,302,514	2,208,461	11,413	Yes

SCONO$_X$™ provides the highest level of CO reduction. However, it cost $21,706 per ton of CO removed. It is ruled out as a control option.

The next most effective control is a combination of DLN combustors and CO oxidation. The adverse impacts include an energy loss from the performance loss due to the pressure drop across the CO catalyst and emissions of sulfates condense as additional PM_{10} or $PM_{2.5}$. However, the cost is prohibitive ($11,413 per ton of CO removed), and it is ruled out as a control option.

Combustion control is selected as BACT for CO control with the limit of 9 ppm at 15% O_2 (annual average) without duct burners firing and 11.5 ppm at 15% O_2 with duct burner firing (annual average).

2. Auxiliary Boiler

The 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 small combustion unit is prohibitive. However, 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 0.084 lb/MMBTU. Thus, boiler design and good operating practices are proposed as BACT for controlling the CO emissions from the auxiliary boiler. The proposed BACT will not have any adverse environmental or energy impacts.

3. Emergency Diesel generator and Diesel Fire Pump

A review of the RBLC indicates that this type of equipment has not been required to install additional CO controls because of intermittent operation. An uncontrolled CO emission factor of 0.95 lbs/MMBtu for the emergency generator and 0.85 lbs/MMBtu for diesel fire pump engine is based on AP-42. Good combustion control for CO emissions is proposed as BACT. The proposed BACT has no adverse environmental or energy impacts. DEQ agrees that engine design is acceptable as BACT.

c. SO_2 and H_2SO_4 BACT Review

1. Gas Turbines and Duct Burners

Control techniques available to reduce SO_2 and H_2SO_4 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 application, 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 next available technique is the use of low sulfur fuels. The applicant proposed the use of pipeline natural gas with sulfur content of 2 grains of sulfur per 100 scf gas fuel or 65 ppm by weight. There are no adverse environmental or energy impacts associated with the proposed control alternative. It is accepted as BACT.

2. Auxiliary Boilers

FGD systems are not used with boilers firing very low sulfur fuels such as natural gas. The use of pipeline natural gas is proposed as BACT. There are no adverse environmental or energy impacts associated with the proposed control alternative.

3. Emergency Diesel Generator and Diesel Fire Pump

The cost of add-on controls on intermittently operated equipment is prohibitive. Thus, the use of low sulfur fuel is proposed as the BACT. There are no adverse environmental or energy impacts associated with the proposed control alternative.

d. VOCs BACT Review

1. **Combustion Turbines and Duct Burners**

The most stringent VOC control level for gas turbines has been achieved through advanced low NO_X combustors or catalytic oxidation for CO control. According to the list of turbines in the RBLC Clearinghouse with limits on VOC, oxidation catalyst systems represent BACT for VOC control in only 6 of the 27 facilities listed. An oxidation catalyst designed to control CO would provide a side benefit of controlling in the range of 10 to 44 percent of VOC emissions.

The next level of control is combustion controls where VOC emissions are minimized by optimizing fuel mixing, excess air, and combustion temperature to assure complete combustion of the fuel. Therefore, the level of operational control is accepted as BACT for VOC control. The proposed BACT will not have any adverse environmental or energy impacts.

2. Auxiliary Boilers

The 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 small combustion units is prohibitive. However, optimizing boiler-operating conditions will minimize VOC emissions. The maximum estimated VOC emission rate is 0.0055 lbs/MMBTU. Thus, boiler design and good operating practices are proposed as BACT for controlling VOC emissions from the auxiliary boilers. The proposed BACT will not have any adverse environmental or energy impacts.

3. Emergency Diesel Generator and Diesel Fire Pump

A review of the RBLC indicates that this type of equipment has not been required to install additional VOC controls because of intermittent operation. Good combustion control practices represent BACT for VOC. The proposed BACT has no adverse environmental or energy impacts. DEQ agrees that engine design is acceptable as BACT.

e. PM BACT Review

1. Combustion Turbines and Duct Burners

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 that particulate matter to be less than 1 micron, so all emissions are considered as PM_{10}. The PM_{10} emissions from the combustion of natural gas will 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, their use is in and of itself a highly efficient method of controlling emissions. The maximum estimated PM_{10} emission rate is 0.008 lbs/MMBTU from the turbines with duct burners firing. Based on the EPA's RBLC database, there are no BACT precedents that have included an add-on TSP/PM_{10} control requirement for natural gas-fired combustion turbines. Therefore, BACT for PM_{10} emissions from the combustion turbines is proposed to be the use of a low ash fuel and efficient combustion, without further analysis.

This BACT choice will be protective of any reasonable opacity standard. 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. There are no adverse environmental or energy impacts associated with the proposed control alternative.

2. Auxiliary Boilers

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 0.0076 lbs/MMBTU. The EPA's RBLC database research indicates that there are no BACT precedents for TSP/PM_{10} requiring add-on controls. Therefore, BACT for TSP/PM_{10} is proposed to be the use of a low ash fuel and efficient combustion. Opacity is also not an issue with this type of application, except for the condensation of moisture during periods of low ambient temperature. There are no adverse environmental or energy impacts associated with the proposed control alternative.

3. Emergency Diesel Generator and Diesel Fire Pump

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 EPA's RBLC shows that good combustion control and/or good engine design is the most stringent requirement for this application. 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, without further analysis.

4. Cooling Towers

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 specifically 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 Smith Pocola Energy Project plans to use drift eliminators that reduce drift to a guaranteed level of 0.001 percent of circulating water flow. Therefore, this level of control is proposed as BACT for cooling tower particulate emissions. The proposed BACT will not have any adverse environmental or energy impacts.

B. Case-By-Case MACT Determination

As previously noted in the emissions section, this facility is a major source of HAPs, and thus a 112g case-by-case MACT determination for Hazardous Air Pollutants is required. An equivalent emission limitations, also referred to as a MACT emission limitation, must be determined on a case-by-case basis for the facility. For new sources, the MACT emission limitation will be no less stringent than the emission control that is achieved in practice by the best controlled similar source. The emissions reduction must achieve a maximum degree of HAP emission reduction with consideration to the cost of achieving such emission reductions, and the non-air-quality health and environmental impacts, and energy requirements. Since this determination is similar to that of the BACT determination, it is included in this section of the permit. The process to be followed is similar to that already performed in the previous BACT determination, and the technologies to be analyzed are similar. Thus, much of that previously presented will not be repeated here.

There are no specific controls for HAP emissions in use on existing turbines. However, oxidation catalysts have been installed on stationary combustion turbines for the purpose of controlling emissions of CO and some VOCs. These oxidation catalysts have the potential to oxidize organic HAPs as well. Therefore, they are being considered as potential MACT control devices for combustion turbines.

The performance of these oxidation catalyst systems on combustion turbines is reported to control 85 to 95 percent VOC emissions. Similar emission reductions are also achieved on HAP pollutants. Therefore, $SCONO_X^{TM}$ and CO catalysts are considered as potential MACT. The following tables provide information on emission control, cost analysis and environmental impacts.

	Emissions	Economic Impacts			Env. Impacts
Control Technology	HAPs emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Cost Effectiveness ($/tons)	Adverse Impacts (yes/no)
$SCONO_X^{TM}$	50.59	14,922,733	5,444,139	107,613	Yes
CO Catalyst	45.26	1,302,514	2,208,460	48,795	Yes

$SCONO_X^{TM}$ provides the highest level of reduction (95%). However, the high cost of emission reductin ($107,613 per ton of HAP removed) rules it out as a control option. The next most effective control technology is a combination of the Dry Low NO_X combustors with a CO catalyst. When 85% of HAP reduction is achieved, the cost effectiveness is $48,795. The cost of this technology is also prohibitive.

A case by case MACT determination therefore concludes that good combustion practices and dry low NO_X combustors constitute MACT.

C. AIR QUALITY IMPACTS

Prevention of Significant Deterioration (PSD) is a construction air pollution 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 analysis is required for the Class II area.

Modeling conducted by the applicant and reviewed by the DEQ demonstrated that emissions from the facility will exceed the PSD modeling significance levels for NO_2, SO_2 and PM_{10};

however, emissions of CO resulted in concentrations below the modeling significance levels. A full impact analysis was required for NO_2, SO_2 and PM_{10}.

Description of Air Quality Dispersion Models

The air quality modeling analyses employed USEPA's Industrial Source Complex (ISC-PRIME) model (USEPA, 1998). The ISC-PRIME model is recommended as a guideline model for assessing the impact of aerodynamic downwash in the draft revised 40 CFR 51 Appendix W, Guideline on Air Quality Models (FR Vol. 65, No.78/Friday, April 21, 2000). The ISC-PRIME (Version 98069) consists of a short-term model (ISCST3). The regulatory default options were selected such that USEPA guideline requirements were met.

The Comprehensive Air Quality Model with Extensions (CAMx) was used to evaluate the proposed facility's impact on Oklahoma's ozone attainment status. CAMx is a Eulerian photochemical grid model that allows for integrated assessment of gaseous and particulate air-pollution over a regional scale.

The VISCREEN model was employed to calculate visibility impacts at both Upper Buffalo and Caney Creek Class I areas. The model was run in the Screening Level 1 mode following guidance in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1992).

GEP Stack Height and Plume Downwash

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 which 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.

ISC-PRIME explicitly treats the trajectory of the plume near the building, and uses the position of the plume relative to the building to calculate interactions with the building wake. ISC-PRIME calculates fields of turbulence intensity, wind speed, and the slopes of the mean streamlines as a function of the projected building dimensions. These fields gradually decay to ambient values downwind of the building. ISC-PRIME determines the change in plume centerline location with downwind distance and the rate of plume dispersion. Plume rise incorporates the descent of the air containing the plume material, and rise of the plume relative to the streamlines due to buoyancy or momentum effects. ISC-PRIME addresses the entire structure of the wake, from the cavity immediately downwind of the building, to the far wake. The building cavity can be defined as the region bounded above by the separation streamline originating at the upwind edge of the roof, and bounded downwind of the building by the reattachment streamline. The cavity is bounded laterally by the streamlines emanating from the corners of the building. Depending on the building geometry, there can be a separate roof-top and downwind cavity, or a single recirculation cavity. The cavity downwind of the building is often called the near-wake. The wake beyond the reattachment streamline is called the far wake. The entire wake envelope bounds the building recirculating cavities and the far wake.

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 modified for use within ISC-PRIME and 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 ISC-PPRIME 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). The input to the BREEZEWAKE preprocessing program consisted of proposed power plant exhaust stacks (four CTs, two twelve-cell cooling towers and an auxiliary boiler) and building dimensions.

Meteorological Data

The meteorological data used in the dispersion modeling analyses consisted of five years (1986-1988, 1990, 1991) of hourly surface observations from the Ft. Smith, Arkansas, National Weather Service Station and coincident mixing heights from Oklahoma City (1986-1988) and Norman, Oklahoma (1990 and 1991). 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 Ft Smith station during this period was 7 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.

Receptor Grid

The receptor grid for the ISC3 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. Medium grid receptors were used to locate the maximum impact areas. The scenarios were then reevaluated placing fine grid receptors in maximum impact areas to arrive at a final maximum impact. All receptors were modeled with 7.5 minute terrain data produced by the United States Geological Survey (USGS). The coordinates were derived from the NAD 27 State Plane Coordinate System. All quadrangles used to develop the gridded terrain data within the radius of impact for the proposed facility were based on the NAD 27 system.

Modeled Emission Rates and Stack Parameters

The stack emission rates and parameters needed for the proposed power plant included each of the four exhaust stacks of the four CTs and the exhaust stack of the auxiliary boiler. 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	Easting	Northing	Stack Height	Stack Temperature	Stack Velocity	Stack Diameter
	m	m	Ft	°F	Ft/sec	Ft
Turbine No.1	369183.54	3906845.37	148	205	59.4	19
Turbine No.2	369199.75	3906878.28	148	205	59.4	19
Turbine No.3	369234.9	3906951.44	148	205	59.4	19
Turbine No.4	369249.68	3906982.53	148	205	59.4	19
Auxiliary Boiler	369223.17	3906931.93	55	350	30	2
Diesel Engine	369227.73	3906976.43	45	950	62	0.67
Cooling Towers(1)	369348.17	3907116.72	45	77	29	28

(1)Two twelve-cell cooling water towers modeled as twenty-four separate point sources.

Emission Rates[1]				
Source	CO	PM_{10}	SO_2	NO_X
	Lb/hr	Lb/hr	Lb/hr	Lb/hr
Turbine No.1[2]	89.4	27.6	13.84	160.0
Turbine No.2[2]	89.4	27.6	13.84	160.0
Turbine No.3[2]	89.4	27.6	13.84	160.0
Turbine No.4[2]	89.4	27.6	13.84	160.0
Auxiliary Boiler	7.9	0.72	0.55	9.4
Diesel Engine	1.67	0.55	0.50	7.75
Cooling Towers	0	14.16	0	0

(1) Emission rates listed are as modeled. Permitted emission rates are less than those reported here except for SO_2. SO_2 modeling was conducted after emission rates were changed and reflect permitted emissions.
(2) Includes the CTG and the duct burner.

A screening was conducted to determine which pollutants exceeded the modeling significance levels. The highest modeled pollutant concentration for each averaging time is used to determine whether the source will have a significant ambient impact for the pollutant.

Significance Level Comparisons			
Pollutant	**Averaging Period**	**Maximum Concentrations (μg/m³)**	**Significance Level (μg/m³)**
NO_2	Annual	20.28	1
CO	8-hour	117	500
	1-hour	170	2000
PM_{10}	Annual	4.11	1
	24-hour	20.73	5
SO_2	Annual	1.64	1
	24-hour	7.42	5
	3-hour	19.93	25

The modeling indicates facility emissions will result in ambient concentrations below the significance levels in which an area of impact is defined for CO and SO_2 (3-hour standard) but exceed the significance levels for NO_2, SO_2 and PM_{10}. Therefore, additional modeling for PSD increment and NAAQS compliance was required for NO_2, SO_2 and PM_{10}.

<u>NAAQS Modeling</u>

The emissions of NO_X, SO_2 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 determined in the significance analysis. Because the significant impact radii for both pollutants extend into Arkansas, the modeling of background sources was conducted to comply with both ODEQ requirements as well as requirements of the Arkansas Department of Environmental Quality (ADEQ). The modeling parameters used for the additional sources within the impact area were taken from the most recent ODEQ and ADEQ emission inventories. The emission rates for modeled sources within the impact area were modeled based on potential emissions provided by ODEQ and ADEQ.

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. Based on this procedure all background sources in Oklahoma were eliminated from the NAAQS analysis except AES Shady Point. Arkansas does not allow the use of the “20D Rule”, therefore, the total source list generated by ADEQ was evaluated.

The area of impact (AOI) is the circular area with a radius extending from the Project’s center to the most distant receptor where a significant impact is predicted. The following table lists the AOI determined for this analysis. Background sources for Oklahoma included all facilities within the AOI plus 50 km and not eliminated by the the “20D Rule.” All sources in Arkansas within the AOI plus 50 km are included.

Radius Of Impact		
Pollutant	Standard	Radius
		kilometers
NO_2	Annual	3.9
PM_{10}	Annual	1.1
PM_{10}	24-hour	3.7
SO_2	Annual	0.37
SO_2	24-hour	0.37

The following table lists the background sources and parameters used in the modeling for the NAAQS analysis.

NAAQS Analysis Background Sources

Source/Point	NO_2	PM_{10}	SO_2	Stack Height	Stack Temp.	Stack Velocity	Stack Diameter
	Lb/hr	Lb/hr	Lb/hr	Ft	°F	Ft/sec	Ft
AES Shady Point							
Stack 1	382.50	22.6	590.75	350	325	20.9	17
Stack 2	382.50	22.6	590.75	350	325	20.9	17
Stack 3	382.50	22.6	590.75	350	325	20.9	17
Stack 4	382.50	22.6	590.75	350	325	20.9	17
Whirlpool Corporation							
Stack 4	1.87			48	80	38.8	3.5
Stack 17	22.52			51	500	0	4
Quanex Corporation							
Stack 1	36.76	22.88	75.98	73	180	66.2	15
Stack 2	6.3	0.62		110	1280	45.9	4.3
Stack 3	6.3	0.62		35	410	43.8	3.1
Stack 4	5.13	0.5		53	700	99	4.79
Stack 5	5.38	0.52		53	700	99	4.79
Stack 8	0.48			131	120	5	15
Stack 9	2.20			131	120	5	15
Stack 10		0.18		12	70	45	2
Sparks Regional							
Stack 1	20.48			29.8	528	80	1.12
Stack 2	15.36			29.8	528	80	1.12
Stack 3	15.36			29.8	528	80	1.12
Stack 4	15.36			29.8	528	80	1.12
Stack 5	15.36			29.8	528	80	1.12
Stack 6	15.36			29.8	528	80	1.12
Stack 7	2.8			22.0	350	30	2.0
Stack 9	0.33			40.0	350	10	1.7
Stack 10	0.33			40.0	350	10	1.7
Stack 11	1.4			22.0	350	25	1.8
Stack 12	1.4			22.0	350	25	1.8
Stack 13	15.3			24.0	400	3.5	0.5
Stack 14	15.3			24.0	400	3.5	0.5
Stack 15	15.3			24.0	400	3.5	0.5
Stack 16	15.3			24.0	400	3.5	0.5
Stack 17	15.3			24.0	400	3.5	0.5
Stack 18	15.3			24.0	400	3.5	0.5
Stack 19	0.34			28.0	300	10	1.4
Stack 21	1.87			22.0	350	30	2.0

The NO_2 annual, PM_{10} annual, PM_{10} 24-hour high 2nd high, SO_2 annual, and SO_2 24-hour 2nd 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 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 5 years or the sixth high over a five year period to demonstrate compliance with the PM_{10} standards. The use of the high second high is considered to be conservative. The applicant used the 1999 annual mean data from the Muskogee monitor (No. 401010167-1) to provided background NO_2 and the 2000 annual mean data for SO_2 background concentrations. The maximum value from the most recent year (2000) was used for the 24-hour SO_2 standard. The PM_{10} background concentrations were obtained from the Ft. Smith monitor. The maximum value from the most recent year (1998) of data was used for the 24-hour standard. The annual mean value from 1998 was used for the annual standard.

NAAQS Analysis for NO_2 Annual and PM_{10} 24-hour and Annual				
Pollutant	Refined Model Maximum	Highest Monitored Background	Refined + Background	NAAQS Limit
	($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)
NO_2 Annual	21.06	15.27	36.3	100
PM_{10} Annual	4.12	24.6	28.7	50
PM_{10} 24-hour[1]	21.37	52	73.4	150
SO_2 Annual	2.52	5.3	7.82	80
SO_2 24-hour	18.10	58.3	76.40	365

[1]The High 2nd High modeled concentration for the PM_{10} 24-hour standard was used to demonstrate compliance with the NAAQS.

The applicant participated in the ozone impact study conducted by Environ (March 20, 2000). The study was done to assess the ozone impacts in Oklahoma due to proposed new electrical generating units (EUGs) in the region. CAMx was run for a 1995 Base Case emissions scenario and the model-estimated ozone concentrations were compared with the observed values of a June 1995 ozone episode. EPA has developed a set of model performance goals for ozone to aid in the determination that the model is working adequately. The CAMx model performance statistics for all days of the June 1995 episode meet EPA's model performance goals by a wide margin (usually by over a factor of 2). Additional analysis of the spatial distribution of the predicted and observed 1-hour and 8-hour ozone concentrations revealed that the model exhibited a fairly good job of estimating the spatial patterns of the observed ozone concentrations. CAMx was then applied using the Oklahoma 32, 16, and 4 kilometer grids and the June 18-22, 1995 episode for two future year emission scenarios:

2007 CAA Base Case: Emission in 2007 assuming growth and all Clean Air Act Amendment (CAA) mandated controls.

2007 New OK Sources: 2007 CAA Base Case including emissions from the proposed New Oklahoma Sources added.

The year 2007 was selected for the future-year assessment because growth and control factors were readily available from the Ozone Transport Assessment Group (OTAG) and Dallas-Fort Worth ozone control plan development modeling domain. Emissions from the New Oklahoma City Sources were estimated to not increase ozone in the Tulsa-Oklahoma City area to above the 1-hour ozone standard. Therefore, emissions from the proposed New Sources are estimated not to cause or contribute to any violations of the 1-hour ozone standard in Oklahoma. As the New Oklahoma Sources are estimated to produce changes in peak 8-hour ozone concentrations that are much less than 1 ppb, then they are estimated to have no measurable effect on peak 8-hour ozone concentrations in the Tulsa and Oklahoma City areas.

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 Le Flore County by the AES Shady Point Permit in 1986. The NO_2 minor source baseline date was triggered for Le Flore County by the application for this permit. In Arkansas, both NO_2 and PM_{10} were triggered for Sebatian County in 1993. However, only PM_{10} was triggered for Franklin County (1978). ODEQ under guidance from EPA allows the use of the "20D Rule" for increment consumption evaluations as well as NAAQS evaluations. Therefore, the list of sources from ODEQ was again pared down to a single source, AES Shady Point. ADEQ approved the following protocol for evaluating background sources consuming increment in Arkansas.

- Facilities located in PSD triggered counties:
    1. If inside the Radius of Impact (ROI) and permitted since the baseline date for the county, include in the analysis.
    2. If inside the ROI but permitted prior to the minor source baseline date for the county, exclude in the analysis.
    3. If outside the ROI but within 50km + ROI and deemed "small" sources, exclude in the analysis.
    4. If outside the ROI but within 50km + ROI and permitted prior to the minor source baseline date for the county, exclude from the analysis.
    5. If outside the ROI but within the 50km +ROI, permitted since the minor source baseline date, and not "small", include in the analysis.
    6. If outside 50km + ROI, exclude from analysis.

- Facilities located in non-triggered counties (all other counties):
  1. If inside ROI, include in analysis.
  2. If outside 50km + ROI, exclude from analysis.
  3. If within 50km + ROI, unless "large", exclude from analysis.

ADEQ does not apply an absolute emission rate to determine values for "small" or "large" but instead relies on engineering judgment as to whether a source's impact should be included. For this review, facilities with emission rates below five tons per year were considered "small" and facilities with emission rates greater than 100 tons per year were considered "large". The following background sources were modeled to demonstrate compliance with the increment consumption levels. Model identification numbers were provided rather than stack identification numbers.

PSD Increment Analysis Background Sources								
Source	Model ID	SO_2	NO_2	PM_{10}	Stack Height	Stack Temp	Stack Velocity	Stack Diameter
		Lb/hr	Lb/hr	Lb/hr	Ft	F	Ft/s	Ft
Acme Brick	Source66	21.34	0.89	1.70	28.0	605	44.00	3.5
Acme Brick	Source67		0.89	1.70	28.0	605	44.00	3.5
Acme Brick	Source68		0.89	1.70	28.0	605	44.00	3.5
AES Shady Point	Source1	336.7	0.00	22.6	350.0	325	20.93	17.0
AES Shady Point	Source2	334.8	0.00	22.6	350.0	325	20.93	17.0
AES Shady Point	Source3	320.0	0.00	22.6	350.0	325	20.93	17.0
AES Shady Point	Source4	322.62	0.00	22.6	350.0	325	20.93	17.0
Baker &Bros	Source288		0.00	1.32	40.6	70	13.00	1.0
Baker &Bros	Source289		0.00	1.32	36.9	70	13.00	0.9
Baldor Electric	Source27		0.00	1.51	24.1	78	28.87	2.0
City of Ft Smith	Source26		3.70	1.21	28.0	2000	60.00	0.1
Correll, INC.	Source96		0.00	0.02	26.0	70	34.00	2.1
Correll, INC.	Source97		0.00	0.02	25.0	100	1.50	1.0
Correll, INC.	Source98		0.00	0.02	20.0	240	8.00	2.0
Correll, INC.	Source99		0.00	0.02	45.0	0	14.00	3.0
Ft Chaffee	Source233		3.10	0.00	14.0	1060	109.50	0.8
Ft Chaffee	Source235		0.02	0.00	25.0	500	7.45	1.0
Ft Chaffee	Source249		4.40	0.00	19.0	1050	164.90	1.0
Ft James	Source70		0.15	0.01	47.0	155	58.27	1.8
Ft James	Source71		0.15	0.01	47.0	155	58.27	1.8
Ft James	Source72		0.15	0.01	47.0	155	58.27	1.8
Ft James	Source73		0.15	0.01	47.0	155	58.27	1.8
Ft James	Source74		0.15	0.01	47.0	155	58.27	1.8
Ft James	Source75		0.15	0.01	47.0	155	58.27	1.8
Ft James	Source76		0.06	0.00	22.1	115	31.00	2.1
Ft James	Source77		0.06	0.00	22.1	115	31.00	2.1
Ft James	Source78		0.05	0.00	20.7	108	29.40	1.5

PSD Increment Analysis Background Sources								
Source	Model ID	SO_2	NO_2	PM_{10}	Stack Height	Stack Temp	Stack Velocity	Stack Diameter
		Lb/hr	Lb/hr	Lb/hr	Ft	F	Ft/s	Ft
Ft James	Source79		0.01	0.00	18.0	137	2.76	1.5
Ft James	Source80		0.01	0.00	21.0	137	6.06	1.0
Ft James	Source81		0.01	0.00	21.1	137	6.36	1.0
Ft James	Source82		0.01	0.00	21.0	137	2.29	1.7
Ft James	Source84		0.01	0.00	20.0	137	2.29	1.7
Ft James	Source85		0.02	0.00	19.8	300	39.71	0.9
Ft James	Source86		0.01	0.00	18.8	137	6.06	1.0
Ft James	Source89		0.00	0.56	18.0	78	11.69	4.7
Ft James	Source90		0.00	1.28	29.0	78	13.31	6.6
Ft James	Source91		0.00	2.26	34.0	78	13.56	8.7
Ft James	Source92		0.00	1.62	28.0	78	13.30	7.4
Ft James	Source93		0.00	1.73	29.2	78	109.00	2.7
Ft James	Source94		0.00	0.93	20.0	78	7.81	7.3
Ft James	Source95		0.00	1.22	24.0	78	14.12	6.3
Ft James	Source104		0.00	2.26	34.0	78	13.56	8.7
Ft James	Source105		0.00	1.27	34.0	78	13.00	8.7
Gerber Products	Source11	3.7	20.06	0.00	52.0	375	4.50	4.0
Gerber Products	Source12		0.11	0.00	33.0	1130	134.50	0.3
Gerber Products	Source37		0.00	1.98	52.0	375	4.50	4.0
Gerber Products	Source38		0.00	0.04	36.7	78	52.00	1.3
Gerber Products	Source39		0.00	0.04	37.7	78	53.00	1.3
Gerber Products	Source40		0.00	0.06	34.7	192	12.00	2.0
Gerber Products	Source41		0.00	0.06	34.7	192	12.00	2.0
Gerber Products	Source42		0.00	0.06	34.7	192	12.00	2.0
Gerber Products	Source50		0.00	0.06	34.7	192	12.00	2.0
Gerber Products	Source51		0.00	0.06	34.7	192	12.00	2.0
Gerber Products	Source54		0.00	0.06	34.7	192	12.00	2.0
Gerber Products	Source55		0.00	0.02	33.0	1130	134.50	0.0
GNB Tech	Source13		0.51	0.00	26.0	80	65.00	2.0
GNB Tech	Source25		0.40	0.00	26.0	80	67.00	1.8
GNB Tech	Source56		0.00	0.26	26.0	80	65.00	2.0
GNB Tech	Source57		0.00	0.26	26.0	81	65.00	2.0
GNB Tech	Source58		0.00	0.95	26.0	81	65.00	2.0
GNB Tech	Source59		0.00	0.59	26.0	80	65.00	2.0
GNB Tech	Source60		0.00	0.39	26.0	80	67.00	1.8
GNB Tech	Source61		0.00	0.71	26.0	80	63.30	2.4
GNB Tech	Source62		0.00	0.78	26.0	80	63.30	2.4
Graphic Packaging	Source239		0.00	3.17	25.0	78	0.00	1.0

PSD Increment Analysis Background Sources								
Source	Model ID	SO_2	NO_2	PM_{10}	Stack Height	Stack Temp	Stack Velocity	Stack Diameter
		Lb/hr	Lb/hr	Lb/hr	Ft	F	Ft/s	Ft
Mead Containerboard	Source228	7.9	1.80	0.11	25.0	400	30.00	1.7
Mead Containerboard	Source229		0.23	0.02	25.0	-370	10.00	1.0
Mead Containerboard	Source230		0.00	19.60	60.0	78	70.00	7.5
Mead Containerboard	Source231		0.00	15.50	60.0	78	70.00	7.5
Mead Containerboard	Source232		0.00	0.06	30.0	78	0.00	1.1
Mead Containerboard	Source234		0.00	0.06	30.0	78	0.00	1.0
Mead Containerboard	Source236		0.00	0.06	30.0	78	0.00	1.2
Mead Containerboard	Source237		0.00	0.06	30.0	78	0.00	1.0
Mead Containerboard	Source238		0.00	0.06	30.0	78	0.00	1.0
Noram-Walker	Source100		19.49	0.00	27.0	750	90.00	1.0
Noram-Walker	Source101		18.16	0.00	27.0	750	90.00	1.0
Noram-Walker	Source102		19.49	0.00	27.0	750	90.00	1.0
Noram-Walker	Source103		22.89	0.00	30.0	750	90.00	1.0
Norton Alcoa PR	Source10		2.00	0.00	157.5	76	300.00	3.4
OK Foods	Source43		1.16	0.11	6.0	95	4.00	4.0
OK Foods	Source44		0.00	0.16	6.0	0	15.00	2.0
OK Foods	Source45		0.48	0.07	25.0	95	2.00	2.5
OK Foods	Source46		1.16	0.11	6.0	95	4.00	4.0
OK Foods	Source47		1.71	0.18	9.0	350	23.00	1.6
OK Foods	Source48		0.04	0.02	10.0	225	22.00	1.3
OK Foods	Source49		0.27	0.05	10.0	175	0.00	0.8
OK Foods	Source27		0.10	0.00	9.0	200	0.00	1.7
OK Foods	Source35		0.20	0.00	9.0	350	62.00	0.8
OK Foods	Source38		0.27	0.00	10.0	175	0.00	0.8
OK Foods	Source39		0.27	0.00	10.0	175	0.00	0.8
OK Foods	Source40		0.27	0.00	10.0	175	0.00	0.8
OK Foods	Source41		0.54	0.00	12.0	250	46.00	1.2
OK Foods	Source42		0.34	0.00	10.0	310	63.00	1.0
OK Foods	Source78		0.00	0.01	9.0	200	0.00	1.7

PSD Increment Analysis Background Sources								
Source	Model ID	SO_2	NO_2	PM_{10}	Stack Height	Stack Temp	Stack Velocity	Stack Diameter
		Lb/hr	Lb/hr	Lb/hr	Ft	F	Ft/s	Ft
OK Foods	Source79		0.00	0.16	6.0	78	15.00	2.0
OK Foods	Source80		0.00	0.02	9.0	350	62.00	0.8
OK Foods	Source81		0.00	0.96	9.0	200	62.00	0.8
OK Foods	Source82		0.00	0.03	10.0	175	0.00	0.8
OK Foods	Source83		0.00	0.03	10.0	175	0.00	0.8
OK Foods	Source84		0.00	0.03	10.0	175	0.00	0.8
OK Foods	Source85		0.00	1.44	9.0	170	62.00	0.8
OK Foods	Source86		0.00	0.05	12.0	250	46.00	1.2
OK Foods	Source87		0.00	1.44	9.0	170	62.00	0.8
OK Foods	Source88		0.00	0.96	10.0	170	63.00	1.0
OK Foods	Source100		0.00	0.03	10.0	310	63.00	1.0
Owens Corning	Source69		4.49	4.00	24.0	696	106.00	2.5
Owens Corning	Source76		0.00	0.22	43.0	80	37.80	2.3
Planters Lifesavors	Source28	0.114	0.32	0.00	48.0	180	82.00	2.3
Planters Lifesavors	Source29	0.114	0.32	0.00	48.0	180	82.00	2.3
Planters Lifesavors	Source30	0.114	0.32	0.00	58.0	320	66.00	1.5
Planters Lifesavors	Source31	0.114	0.41	0.00	58.0	320	66.00	1.5
Planters Lifesavors	Source32	0.114	0.32	0.00	58.0	320	66.00	1.5
Planters Lifesavors	Source33	0.114	0.11	0.00	60.0	500	64.70	1.5
Planters Lifesavors	Source34	0.228	0.23	0.00	18.0	180	5.00	1.5
Planters Lifesavors	Source36	0.228	0.41	0.00	45.0	150	10.00	1.5
Planters Lifesavors	Source37	0.114	0.11	0.00	50.0	250	5.00	1.5
Quanex Corp.	Source18	75.98	0.00	22.86	73.0	180	66.20	15.0
Quanex Corp.	Source19		0.00	0.62	110.0	1280	45.90	4.3
Quanex Corp.	Source20		0.00	0.62	35.0	410	43.80	3.1
Quanex Corp.	Source21		0.00	0.52	53.0	700	99.00	4.8
Quanex Corp.	Source22		0.00	0.18	53.0	700	99.00	4.8
Quanex Corp.	Source23		0.48	0.00	131.0	120	5.00	15.0
Quanex Corp.	Source24		2.20	0.00	131.0	120	5.00	15.0
Quanex Corp.	Source25		0.00	0.11	12.0	70	45.00	2.0
Reliant Energy	Source260		22.18	0.00	16.0	880	33.70	0.7
Reliant Energy	Source261		22.18	0.00	16.0	721	29.50	0.7
Reliant Energy	Source285		22.18	0.00	16.0	693	30.20	0.7
Rheem Mftg	Source14		0.91	0.00	40.0	160	0.00	1.5
Rheem Mftg	Source15		0.25	0.00	38.0	350	17.20	3.5
Rheem Mftg	Source62		0.41	0.00	56.0	380	7.00	2.5
Rheem Mftg	Source63		0.02	0.00	27.0	1400	0.00	1.5
Rheem Mftg	Source64		0.02	0.00	27.0	1400	0.00	1.5

PSD Increment Analysis Background Sources								
Source	Model ID	SO_2	NO_2	PM_{10}	Stack Height	Stack Temp	Stack Velocity	Stack Diameter
		Lb/hr	Lb/hr	Lb/hr	Ft	F	Ft/s	Ft
Riverside Furniture	Source9		0.00	6.49	59.0	78	28.00	2.9
Riverside Furniture	Source10		0.00	1.00	28.0	78	31.00	5.0
Riverside Furniture	Source11		0.00	1.00	28.0	78	27.00	5.0
Riverside Furniture	Source12		0.00	1.00	28.0	78	27.00	5.0
Riverside Furniture	Source13		0.00	6.49	58.0	78	25.00	2.9
Riverside Furniture	Source15		0.00	1.00	29.0	78	27.00	5.0
Riverside Furniture	Source23		0.00	1.00	29.0	78	27.00	5.0
Riverside Furniture	Source24		0.00	1.00	29.0	78	27.00	5.0
Riverside Furniture	Source28		0.00	1.00	29.0	78	27.00	5.0
Riverside Furniture	Source29		0.00	1.00	28.0	78	31.00	5.0
Riverside Furniture	Source30		0.00	6.49	58.0	78	25.00	2.9
Riverside Furniture	Source31		0.00	1.00	31.0	78	27.00	5.0
Riverside Furniture	Source32		0.00	1.00	36.0	78	31.00	5.0
Riverside Furniture	Source33		0.00	1.00	44.0	78	31.00	5.0
Riverside Furniture	Source34		0.00	3.42	31.0	78	8.00	0.8
Riverside Furniture	Source35		0.00	6.49	57.0	78	24.00	2.9
Riverside Furniture	Source36		0.00	1.00	29.0	78	27.00	5.0
Southern Steel	Source9		3.26	0.00	16.5	233	10.00	3.0
Sparks Regional	Source266		1.87	0.00	22.0	350	3.50	2.0
Sparks Regional	Source267		0.12	0.00	28.0	300	3.50	1.4
Sparks Regional	Source268		0.04	0.00	24.0	400	3.50	0.5
Sparks Regional	Source269		0.04	0.00	24.0	400	3.50	0.5
Sparks Regional	Source270		0.04	0.00	24.0	400	3.50	0.5
Sparks Regional	Source271		0.04	0.00	24.0	400	3.50	0.5
Sparks Regional	Source272		0.04	0.00	24.0	400	3.50	0.5
Sparks Regional	Source273		0.04	0.00	24.0	400	3.50	0.5
Sparks Regional	Source274		1.42	0.00	22.0	350	25.00	1.8
Sparks Regional	Source275		1.40	0.00	22.0	350	25.00	1.8
Sparks Regional	Source276		0.33	0.00	40.0	350	10.00	1.7
Sparks Regional	Source277		0.33	0.00	40.0	350	10.00	1.7
Sparks Regional	Source278		2.80	0.00	22.0	350	30.00	2.0
Sparks Regional	Source279		2.35	0.00	29.8	528	80.00	1.1
Sparks Regional	Source280		2.35	0.00	29.8	528	80.00	1.1
Sparks Regional	Source281		2.35	0.00	29.8	528	80.00	1.1
Sparks Regional	Source282		2.35	0.00	29.8	528	80.00	1.1
Sparks Regional	Source283		2.35	0.00	29.8	528	80.00	1.1
Sparks Regional	Source284		1.40	0.00	29.8	528	80.00	1.1
Store Kraft	Source65		0.00	3.68	43.0	64	113.00	0.1

PSD Increment Analysis Background Sources								
Source	Model ID	SO_2	NO_2	PM_{10}	Stack Height	Stack Temp	Stack Velocity	Stack Diameter
		Lb/hr	Lb/hr	Lb/hr	Ft	F	Ft/s	Ft
SW Energy	Source87		3.94	0.00	23.0	810	180.20	1.0
SW Energy	Source88		3.94	0.00	23.0	810	180.20	1.0
Whirlpool	Source16		0.00	0.02	48.0	80	38.80	3.5
Whirlpool	Source17		0.00	2.21	51.0	500	0.00	4.0
Willamette	Source287	7.5	2.10	0.00	58.0	78	0.00	6.0

The following table presents the results of the increment analysis. The applicant has again demonstrated compliance through the application of the NO_2/NO_X ratio of 0.75 as is allowed in the "Guideline on Air Quality Models".

Class II Increment Consumption Analysis			
Pollutant	**Averaging Period**	**Maximum Concentrations ($\mu g/m^3$)**	**Maximum Allowable Increment Consumption ($\mu g/m^3$)**
NO_2	Annual	21.7	25
PM_{10}	Annual	4.78	19
	24-hour[1]	24.22	30
SO_2	Annual	2.3	20
	24-hour[1]	13.36	91

[1]The High 2nd High modeled concentration for the PM_{10} and SO_2 24-hour standards were used to demonstrate compliance with the Increment.

D. 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 level for CO. Neither pre-construction nor post-construction ambient monitoring will be required for this pollutant. However, VOC emissions and NO_2 and PM_{10} modeled concentrations are above the monitoring significance levels. Therefore ozone, NO_2 and PM_{10} pre-construction monitoring is required. The existing Oklahoma DEQ monitoring site (No. 401430174-1) located in Glenpool will provide conservative monitoring data in lieu of pre-construction monitoring. The existing monitor is located in a more affected area and is expected to exhibit higher concentrations due to it's proximity to Tulsa than is experienced in the area of the proposed facility.

The ODEQ NO_2 monitoring site (No. 401010167-1) located in Muskogee is impacted by an inventory and population center greater than that of the Pocola site and will provide conservative data in lieu of preconstruction monitoring.

The ADEQ PM_{10} monitoring site (No. 051310008-1) located in Ft. Smith, Arkansas is 10.3 km Northeast of the proposed facility and will provide conservative data in lieu of preconstruction monitoring.

Comparison of Modeled Impacts to Monitoring Exemption Levels			
Pollutant	**Monitoring Exemption Levels**		**Ambient Impacts**
	Averaging Time	**μg/m³**	**μg/m³**
NO_2	Annual	14	21.06
CO	8-hour	575	117
PM_{10}	24-hour	10	20.96
SO_2	24-hour	13	10.68
VOC	100 TPY of VOC		139 TPY VOC

Monitoring Data Summary			
Pollutant	PM_{10} (μg/m^3)	NO_2 (ppm)	O_3 (ppm)
Monitor ID	051310008-1	401010167-1	401430174-1
Year	1998	2000	2000
First High	52	0.051	0.111
Second High	48	0.051	0.096
Third High	46	--	0.095
Fourth High	45	--	0.092
Annual	24.6	0.008	--

E. Additional Impacts Analysis

1. Mobile Sources

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

2. Growth Impacts

The Smith Pocola Energy Project will employ an average of 200 (300 peak) personnel during the construction phase but will employ only a small permanent staff of less than 25 employees, no significant air quality impact is expected. Construction of the plant would not result in an increase in the number of permanent residents. No significant industrial or commercial secondary growth will occur as a result of the project since the number of permanent employees needed is small. Most labor, material, and service requirements are already in place. The facility does have the capability to provide steam to industrial users. At this time no industrial facility has expressed an interest in the steam produced at the Smith Pocola Project. However, permitting endeavors completed at the time of the potential plant development would be required to address air quality issues.

3. 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_X. NO_X was selected for review since it has been shown to be capable of causing damage to vegetation at elevated ambient concentrations.

To evaluate the potential effects of air pollution on vegetation, Heck and Brandt (1977) recommend the use of a dose analysis. In their summary they presented data collected by several investigators on the growth response of plants to various concentrations and durations. While they qualify this data as being preliminary and not having been subject to rigorous experimentation, they can be applied in this project review. They further caution that the data should only be applied to exposures of periods no longer than 10 to 12 hours. The following table presents data from Heck and Brandt's survey on the potential for plant injury form air pollution.

Concentration (ppm) Producing 5% Injury to Sensitive Vegetation During Short Term Exposure				
Pollutant	Time (hrs)	Sensitive	Intermediate	Resistant
Ozone	0.5	0.2-0.35	0.30-0.55	0.50
	1.0	0.10-0.25	0.20-0.35	0.30
	2.0	0.07-0.20	0.15-0.30	0.25
	4.0	0.05-0.15	0.12-0.26	0.23
	8.0	0.03-0.12	0.10-0.22	0.20
Nitrogen Dioxide	0.5	6.0-12	1-25	20
	1.0	3.0-10	9.0-20	18
	2.0	2.5-7.5	7.0-15	13
	4.0	2.6-6.0	5.0-12	10
	8.0	1.5-5.0	4.0-9.0	8

Source: Heck and Brandt, 1977.

The division of plants into sensitive, intermediate and resistant species is somewhat subjective and varies according to the literature reviewed. However, this table can be used as a general guide on the potential effects of the project. The concentrations presented on the table are those that can produce acute changes or injury (i.e., leaf drop and leaf discoloration) in plants exposed to air pollutants from 0.5 to 8.0 hours.

The lower concentration of NO_X that affect sensitive plants over 0.5 to 8.0 hours of contact can be extrapolated to longer exposure periods to provide a framework for evaluating the importance of the project air pollutant concentrations. As noted by Heck and Brandt, to rely on this extrapolation for periods greater than 24 hours would be of questionable value.

With respect to the longer-term exposures of vegetation to air pollutants, Heck and Brandt cite other data that can provide some basis for long-term evaluation:

- Over a 7-month growing season, a slight chronic response was noted in a variety of plants (i.e., cereal, vegetables, trees, forage, and fruit crops) exposed to a concentration of about 400 $\mu g/m^3$ of SO_2; and
- Slight changes were noted in pine trees exposed to SO_2 concentrations of about 280 $\mu g/m^3$ for 6 months.

Ozone impacts were evaluated through the ozone study conducted by a consortium of new utilities. As the combined impacts of all the New Oklahoma Sources were estimated to produce changes in peak 8-hour ozone concentrations that are much less than 1 ppb or 0.001 ppm which is much smaller than the lowest concentration in the table above, then they are not anticipated to adversely impact vegetation.

Based on the modeling conducted the annual NO_2 ground level concentration is 21.06 $\mu g/m^3$. Converting this value to ppm yields a maximum annual impact of 0.011 ppm. This concentration is much smaller than the lowest concentration in the table above which has been determined to potentially lead to injury of sensitive vegetation. NO_2 emissions from the Smith Pocola Energy Project are therefore not anticipated to lead to injury of vegetation.

The secondary NAAQS are intended to protect the public welfare from adverse effects of airborne effluents. This protection extends to agricultural soil. As previously demonstrated, the maximum predicted NO_2 pollutant concentration from the proposed power plant is well below the secondary 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.

4. 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.

F. 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 105 km northwest of the Caney Creek Class I area and 100 km southwest of the Upper Buffalo Class I area.

Under guidance from the Land Manager representative for the two Class I areas, the applicant was required to evaluate the increment consumption by the new source alone in both areas.

ISCST3 Results at Nearest Class I Areas				
Pollutant	Averaging Time	Upper Buffalo	Caney Creek	Class I Increment Consumption Standard
		$\mu g/m^3$	$\mu g/m^3$	$\mu g/m^3$
NO_2	Annual	0.019	0.010	2.5

PM_{10}	Annual	0.005	0.003	4
PM_{10}	24-hour	0.044	0.035	8
SO_2	Annual	0.050	0.046	2
	24-hour	0.549	0.814	5

As the modeling results are significantly less than the established Class I Increment Consumption Standards, no additional modeling of impacts to the Class I areas is required.

The VISCREEN model was employed to calculate visibility impacts at both Upper Buffalo and Caney Creek. The VISCREEN model was run in the Screening Level I mode following guidance in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1992). PM emissions of 125.83 pounds per hour and NO_X emissions of 655.95 pounds per hour were modeled. Two measures are compared with a threshold value. “Delta E” is the color difference paramter that measures plume perceptiblility. “Contrast: measures the difference in light intensity between the plume and the background. The treshold for Delta E is 2.00, and the model showed a maximum impact of 0.48 and 0.57 for Upper Buffalo and Caney Creek, respectively. The threshold for contrast is 0.05, and the models show a maximum impact of –0.004 and –0.005 for Upper Buffalo and Caney Creek, respectively. The results demonstrate that the project will not cause any adverse or significant visual impacts on the Upper Buffalo or Caney Creek Wilderness areas.

SECTION 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, 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. NSPS standards are addressed 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 252:100-7 (Permits for Minor Facilities) [Not Applicable]

Subchapter 7 sets forth the permit application fees and the basic substantive requirements for permits for minor facilities.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 1 includes the General provisions and other administrative requirements that are addressed by standard conditions in this permit.
Part 3 requires that a source pay the appropriate application fee for a permit.
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 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

Part 7 includes the PSD requirements for attainment areas. These requirements apply to a new major stationary source and any modification to a major source when emissions resulting from the modification produce a significant net emissions increase in any pollutant subject to PSD. Full PSD review of emissions consists of determination of best available control technology (BACT); evaluation of existing air quality and determination of monitoring requirements; evaluation of PSD increment consumption; analysis of compliance with National Ambient Air Quality Standards (NAAQS); evaluation of source-related impacts on growth, soils, vegetation, visibility; and evaluation of Class I area impacts.
The facility is a listed source as a fossil fuel-fired electric plant of more than 250 MMBTU heat input with emissions greater than 100 TPY of any pollutant. PSD review has been completed in Section IV.
Part 9 includes the requirements for major sources affecting nonattainment areas.
Oklahoma currently has no areas designated as nonattainment.

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 practical during normal office hours and no later than 4:30 p.m. the next working day following the malfunction or release. Within ten (10) business days further notice shall be tendered in writing containing specific details of the incident. 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 (Prohibition of Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.
OAC 252:100-19 (Particulate Matter) [Applicable]
Subchapter 19 regulates emissions of particulate matter from fuel-burning equipment. Particulate emission limits are based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power". Thus, the turbines, duct burners, auxiliary boilers, diesel generator and diesel engine are subject to the requirements of this subchapter. As shown in the following table, all units are in compliance with this requirement.

Equipment	Maximum Heat Input (MMBTUH HHV)	Allowable Particulate Emission Rate (lb/MMBTU)	Permitted Particulate Emission Rate (lb/MMBTU)
Turbines	1877	0.165	0.007
Duct Burners	577	0.229	0.010
Auxiliary Boilers	48	0.414	0.0076
Diesel Generator	0.85	0.6	0.10
Diesel Engine	0.64	0.6	0.31

OAC 252:100-25 (Visible Emissions, and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The turbines and duct burners (electric utility steam generating unit) are subject to an opacity limit under NSPS Subpart Da. Thus, they are exempt from the opacity limit at OAC 252:100-25-3. The auxiliary boilers are subject to NSPS Subpart Dc. However, there is no applicable opacity limit under this standard. Thus, it is not exempt from the opacity limit at OAC 252:100-25-3. Other emissions units, i.e., the diesel emergency generator and diesel fire pump are subject to this subchapter. These units will assure compliance with this regulation by ensuring "complete combustion".

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. There is negligible potential to violate this requirement. Thus, no monitoring is required by this permit to assure compliance.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
<u>Part 5</u> limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input. Burning only natural gas with a maximum of 2 grains of sulfur per 100 SCF will result in SO_2 emissions of 0.0056 lb/MMBtu for gas turbine with duct burner firing, which assures compliance. The SO_2 emission factors of 0.51

lb/MMBTU for the emergency diesel generator and 0.29 lbs/MMBTU for the diesel fire pump engine are less than the allowable emission limitation of 0.8 lb/MMBTU for liquid fuels.
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, and equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitoring requirement. Thus, the turbines and duct burners do not require such monitoring.

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 lb of NO_x per MMBtu/hr (two hour maximum). The NO_X emissions from the turbines and duct burners are 0.045 lb/MMBTU which are less than the allowable in OAC 252:100-33. The auxiliary boiler, emergency diesel generators, and the diesel fire pump are below 50 MMBtu/hr heat input and are, therefore, not subject to this regulation.

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 proposed diesel storage tanks will not have a capacity greater than 400 gallons. Additionally, the vapor pressure of diesel is not greater than 1.5 psia.
Part 5 limits the VOC content of coatings 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. The turbines, duct burners, and auxiliary boilers are designed to provide essentially complete combustion of organic materials.

OAC 252:100-41 (Hazardous and Toxic Air Contaminants) [Applicable - State Only]
Part 1 contains the purpose of the subchapter and definitions.
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, 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 adopted by reference as they exist on July 1, 2000. These standards shall apply to both existing and new sources of hazardous air contaminants. 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.

The emissions of acetaldehyde, formaldehyde, hexane, pentane, propylene oxide and sulfuric acid were modeled and shown to be well within the MAAC limits (see Section III).

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]
Records and reports 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 Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not in source category
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-35	Carbon Monoxide	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Existing Municipal Solid Waste Landfills	not in source category

SECTION VII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Not 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 some pollutants. PSD review has been completed in Section IV.

NSPS, 40 CFR Part 60 [Subparts GG, Da and Dc are Applicable]
Subpart Da (Electric Steam Generating Units) affects 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 577 MMBtu/hr is added by duct burners in the HRSGs, they are subject to Subpart Da. However, the gas combustion turbines are not subject to this subpart as stated in 40 CFR 60.40a(b) because the turbines are subject to the requirements of 40 CFR 60 Subpart GG.
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 0.010 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 0.0056 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 0.08 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 requirements will be included in the Specific Conditions.
<u>Subpart Db</u> (Steam Generating Units) affects 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.
<u>Subpart Dc</u> (Industrial-Commercial-Institutional Steam Generating Units) affects units with a design capacity between 10 and 100 MMBTUH heat input and which commenced construction or modification after June 9, 1989, so two 48 MMBtu/hr auxiliary boilers are an affected units. Particulate and SO_2 standards are not established 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)).
<u>Subpart GG</u> (Stationary Gas Turbines) affects combustion turbines which commenced construction, reconstruction, or modification after October 3, 1977, and which have a heat input rating of 10 MMBTUH or more. Each of the proposed turbines has a higher heating value firing rate of 1,877 MMBTU/hr and is subject to this subpart.

Subpart GG NO_X standard for turbines with heat input at peak load greater than 107.2 gigajoules per hour (100 MMBtu/hr) is (§60.332):

$$STD = 0.0075\ (14.4)/Y+F$$

Where
STD = allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis).
Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilohoules per watt hour. F = NO_X emission allowance for fuel-bound nitrogen.

EPA guideline document EMTIC, GD-009 advises to use zero for the value of F with gas turbines. So, the lowest NO_X limit is 0.0075% or 75 ppmdv when Y = 14.4. NO_X emission limitation for each turbine is 9 ppmdv and therefore is more stringent than the Subpart GG standards. Performance testing by Reference Method 20 is required.

Monitoring 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 turbines.

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.

NESHAP, 40 CFR Part 61 [Not Applicable]

Subpart C (Beryllium standard) affects certain processes that process beryllium ores, alloys or wastes. This facility emits beryllium only in trace amounts from combustion processes.

Subpart E (Mercury standard) affects certain sources which process mercury ore, use mercury chlor-alkali cells to produce chlorine, and incinerate or dry wastewater treatment plant sludge. This facility emits mercury only in trace amounts from combustion processes.

Subpart J (Equipment Leaks of Benzene) affects fugitive emissions of benzene from certain equipment operated in benzene service (>10% benzene by weight). This facility emits benzene only in trace amounts from combustion processes and piping of natural gas. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.

Subparts N, O, and P (Arsenic standard) affects arsenic emissions from glass plants, copper smelters, metallic arsenic production facilities. This facility emits arsenic only in trace amounts from combustion processes.

NESHAP, 40 CFR Part 63 [Applicable]

There is no promulgated or proposed Maximum Achievable Control Technology (MACT) standard for the source category, "Combustion (Gas) Turbines," however they are a listed source category pursuant to Section 112(c)(1) of the Clean Air Act. Since the proposed stationary combustion turbines will have major source emission levels, a Clean Air Act Section 112g case-by-case MACT determination for Hazardous Air Pollutants was performed.

Oklahoma regulations (OAC 252:100-8-4(2)) adopt federal regulations (40 CFR Subpart B, Sections 63.40 to 63.44) by reference. These regulations, Requirements for Control Technology for Major Sources of Hazardous Air Pollutants, implement the provisions of the federal Clean Air Act Amendment Section 112(g).

Smith Cogeneration Oklahoma, Inc. proposed a case-by-case MACT determination utilizing best combustion practices and combustion control procedures, including Dry Low NO_x burners and their inherent efficient fuel combustion. There are no control technologies which have been developed to control HAP emissions from combustion turbines. The use of add-on control technologies is limited to the two types of oxidation catalysts which are currently used primarily for CO control. The cost effectiveness of utilizing oxidation catalysts prohibits the use of these technologies for HAP control. This is a result of HAP emissions at a much lower level than CO emissions which are typically controlled. Additionally, the commercial availability, reliability and long range performance of SCONOX™ is still uncertain. Therefore, combustion controls are proposed as case-by-case MACT for the Smith Pocola Energy Project.

Section 112(g) requires that a case-by-case MACT determination follow the general principles of MACT determinations as stated in §63.43(d). These principles state that the MACT determination "shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority". Since there are no HAP controls in use on combustion turbines currently, this principle is satisfied by the proposed MACT determination.

A second principle states that the approved MACT "shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental and energy requirements associated with the emission reduction". This MACT analysis has considered all known control technologies available and has taken into account the considerations listed above. Considerations for extremely high costs and unproven performance associated with such small reductions of HAP are the primary basis for exclusion of these technologies.

Additional principles outlined in §63.43(d)(3) allow for MACT determinations to be based on a specific design, equipment, work practice operational standard or combination of these, when it has been demonstrated that it is not feasible to prescribe a specific emission limitation or control technology. The proposed case-by-case MACT submitted by Smith Cogeneration Oklahoma Inc. provides sufficient data to demonstrate that the available control technologies are not feasible or appropriate means of establishing case-by-case MACT for this facility. Based on the principles prescribed in §63.43(d) for MACT determinations and the requirements of 40 CFR Part 63 Subpart B, a case-by-case MACT is approved as best combustion control practices for the four stationary combustion turbines to be constructed at the Smith Pocola Energy Project.

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

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

No control devices, as defined by this part, are used at this facility. Dry low NO_x burners are considered passive control measures because they prevent the formation of pollutants instead of capturing or destroying them.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
The facility does not store any substance listed in CAAA 90 Section 112(r) above its threshold. 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 this requirement was for the benefit of the regulating agency (Oklahoma DEQ) which can waive this requirement and has 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 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 which involves ozone-depleting substances. Therefore, as currently proposed, 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 VIII. COMPLIANCE

This application has been determined to be Tier III based on the request for a construction permit for a new, previously unpermitted major stationary source that emits 100 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 notice to the landowner about the permit application for the facility was provided.

The applicant published the “Notice of Filing a Tier III Application” in *Daily News & Sun* on May 25, 2000. The notice stated that the application was available for public review at Pocola, Oklahoma City Hall, 204 S. Pocola Boulevard, Pocola, Oklahoma, or at the DEQ Air Quality Division Office at 707 North Robinson, Oklahoma City, Oklahoma. The applicant published the “Notice of Tier III MACT Approval and Draft Permit” in the *Poteau Daily News & Sun*, a daily newspaper in the City of Poteau, LeFlore County, Oklahoma, on May 8, 2001. The notice stated that the draft permit and the Notice of MACT approval were available for public review at Pocola, Oklahoma City Hall, 204 S. Pocola Boulevard, Pocola, Oklahoma, or at the DEQ Air Quality Division Office at 707 North Robinson, Oklahoma City, Oklahoma. The draft permit and the Notice of MACT Approval were also available for public review in the Air Quality section of the DEQ web page: //www.deq.state.ok.us/. This facility is within 50 miles of the Oklahoma border with Arkansas and Arkansas has been notified of the draft permit. No comments were received from the public, Arkansas, federal land manager or EPA Region VI for the draft permit. The applicant published the "Notice of Tier III Proposed Permit" in the *Poteau Daily News*, a daily newspaper in the City of Poteau, LeFlore County, Oklahoma, on June 28, 2001. The notice stated that the proposed permit was available for public review at Pocola City Hall, or at the DEQ Air Quality Division Office. The proposed permit was also available for public review in the Air Quality section of the DEQ web page: //www.deq.state.ok.us/. This facility is within 50 miles of the Oklahoma border with Arkansas and Arkansas has been notified of the proposed permit. No comments were received from the public, Arkansas, federal land manager or EPA Region VI for the proposed permit.

Fees Paid

An initial construction permit fee of $2,000.

SECTION VIII. SUMMARY

The applicant has demonstrated the ability to comply with the requirements of the applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. Compliance and Enforcement concur with the issuance of this permit. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Smith Cogeneration Oklahoma Inc. **Permit Number 2000-115-C (PSD)**
Pocola Energy Project

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on May 7, 2000 and supplement information on August 18, 2000, December 15, 2000 and March 6, 2001, March 29, 2001, April 2, 2001 and April 30,2001. The Evaluation Memorandum dated August 14, 2001, 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)]

	Gas Turbine (each) without Duct Burner firing		
Pollutant	lb/hr	TPY	*ppmdv at 15% O_2
NO_x	63.00	275.9	9
CO	31.00	135.8	9
VOC	3.0	13.14	
SO_2	10.59	46.41	
PM_{10}	9.0	39.42	

*Annual monthly rolling average

	Gas Turbine (each) with Duct Burner firing		
Pollutant	lb/hr	TPY	*ppmdv at 15% O_2
NO_x	109.1	478.0	15.0
CO	62.71	274.7	11.5
VOC	17.13	75.01	
SO_2	13.84	60.66	
PM_{10}	14.77	64.69	
H_2SO_4	4.8	21.02	

*Annual monthly rolling average

Pollutant	Auxiliary Boilers	Emergency Diesel Generator	Diesel Fire Pump

	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
NO_x	9.41	41.22	35.39	8.85	7.75	1.94
CO	7.91	34.64	8.11	2.03	1.67	0.42
VOC	0.52	2.27	1.04	0.26	0.63	0.16
SO_2	0.57	2.47	5.90	1.47	0.51	0.13
PM_{10}	0.72	3.13	1.03	0.26	0.55	0.14

2. Compliance with the authorized emission limits of Specific Condition No. 1 for turbines and duct burners shall be demonstrated by initial performance testing designed to satisfy the requirements of Federal NSPS. [OAC 252:100-8-6(a)]

3. The fuel-burning equipment shall use only pipeline-quality natural gas, except for the diesel emergency generator and diesel fire pump which shall burn diesel fuel with a maximum fuel sulfur content of 0.5 percent by weight. [OAC 252:100-31]

4. A serial number or another acceptable form of permanent (non-removable) identification shall be on each turbine. [OAC 252:100-8-6(a)]

5. Upon issuance of an operating permit, the permittee shall be authorized to operate the turbines, duct burners and auxiliary boilers continuously (24 hours per day, every day of the year). The diesel emergency generator and diesel fire pump shall be limited to 500 hours of operation per 12-month rolling period each. [OAC 252:100-8-6(a)]

6. No emissions, from other than the turbines and duct burners, 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 turbines and duct burners are subject to NSPS, and thus exempt from this requirement.
[OAC 252:100-25]

7. The permittee shall incorporate the following BACT methods for reduction of emissions so as to meet the emission limitations as stated in Specific Condition No. 1.
[OAC 252:100-8-6(a)]

   a. Each combustion turbine and duct burner shall be equipped with dry low-NO_X combustors.
   b. Emissions from the auxiliary boilers, diesel emergency generator and diesel fire pump engine shall be controlled by properly operating per manufacturer's specifications, specified fuel types and limits as listed in Specific Condition #1.

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

9. The turbines are subject to federal New Source Performance Standards, 40 CFR 60, Subpart GG, and shall comply with all applicable requirements. [40 CFR §60.330 to §60.335]

   a. Each turbine shall comply with the standard for nitrogen oxides of §60.332(a)(1).

b. Each turbine shall either comply with the sulfur dioxide emission limitation of 0.015% by dry volume at 15% O_2 or the fuel sulfur content limitation of 0.8% by weight. [§60.333]

c. Monitoring of the sulfur and nitrogen content of the fuel being fired in the turbine is required pursuant to §60.334(b). The AQD has determined that the following custom schedule and testing is appropriate for this section. A quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly "stain tube" analysis is acceptable as sulfur content monitoring of the fuel under NSPS Subpart GG. Other customary monitoring procedures may be submitted with the operating permit for consideration.

d. Excess emissions shall be reported pursuant to §60.334(c).

e. The permittee shall comply with the test methods and procedures of §60.335 except as stated above.

10. The duct burners are subject to federal New Source Performance Standards, 40 CFR 60, Subpart Da, and shall comply with all applicable requirements. [40 CFR §60.42 to §60.49]

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

11. The auxiliary boilers are subject to 40 CFR Part 60 Subpart Dc and shall comply with the following requirements: [NSPS §60.48c(g) and 60.13(i)]

a. The permittee shall maintain records of the amounts of fuel combusted (monthly and 12 month rolling totals).

12. The permittee shall comply with all applicable acid rain program requirements, 40 CFR Part 72, 73 and 75.

13. 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 the applicable limitations in Specific Condition 1, Subpart GG for the combustion turbines, Subpart Da for the duct burners, and Subpart Dc for the auxiliary boiler. [OAC 252:100-8-6(a)]

The permittee shall conduct NO_x, CO, PM_{10}, and VOC testing on the turbines at the 50% and 100% operating rates without duct burner firing, and testing on the turbines at 100% operating rate with duct burners firing at both 70% and 100% duct burners operating rates.

The permittee shall conduct sulfuric acid mist testing on the turbines at 100% operating rate with duct burners firing at the 100% operating rate.

The permittee shall conduct formaldehyde testing on the turbines at the 50% and 100% operating rates, without the duct burners operating.

Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(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.

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.

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 8:	Sulfuric Acid Mist.
Method 10:	Determination of Carbon Monoxide 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 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.

14. 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. When monitoring shows concentrations in excess of the ppm or lb/hr limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions during start-up, shut-down, and malfunction of air

pollution control equipment. Requirements include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions.
[OAC 252:100-9]

15. 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 252:100-43]

a. Emission data as required by the Acid Rain Program.
b. Emission data sufficient to demonstrate the compliance with limits in Specific condition No. 1 and applicable standards of 40 CFR Part 60 Subpart Da and GG.
c. Fuel usage by type and number of hours for auxiliary boilers (monthly and rolling 12 month totals).
d. Operating hours for the fire pump engine and emergency generator (monthly and 12-month rolling totals).
e. Sulfur content of natural gas (quarterly supplier statements or quarterly "stain-tube" analysis) and sulfur content of diesel fuel (each delivery).

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) & (D)]

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

17. The permittee shall apply for a Title V operating permit and an Acid Rain permit within 180 days of operational start-up. [OAC 252:100-8-4(b)(5)]