OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **February 13, 2002**

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

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

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

THROUGH: Peer Review

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

SUBJECT: Evaluation of Permit Application No. **2001-132-C (PSD)**
Mustang Power LLC.
Mustang Power Plant
Mustang, Canadian County
9300 W. Reno
Directions: Take I-40 to Council Road, North to Reno Avenue, West 1.4 Miles to Plant
UTM Zone 14, 620053 Meters Easting and 3925237 Meters Northing

SECTION I. INTRODUCTION

Mustang Power submitted an application for a construction permit on May 10, 2001. The proposed facility (SIC Code 4911) will utilize combined-cycle natural gas-fired combustion turbines with duct burners and heat recovery steam generators (HRSGs) producing a nominal total of 310 MW. The facility plans to begin operations in simple-cycle mode with nominal power output of 180 MW. Maximum operation of each large emission unit will be limited to 3,504 hours per year while operating in simple cycle mode; the facility will be allowed to operate continuously 8,760 hours per year if the facility is configured for combined cycle operations. DEQ has required, and the applicant has agreed, to installation of Selective Catalytic Reduction (SCR) to reduce NOx emissions if/when the facility is converted to combined cycle. 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 45 MW General Electric (GE) LM6000 combustion turbines with four duct burners (each 185 MMBTUH) and HRSGs, auxiliary boiler(s) with a total heat input of 31 MMBTUH, an emergency generator powered by a 1,000 HP diesel engine, a firewater pump powered by a 250 HP diesel engine, two four-cell cooling towers, and a six-cell cooling tower. Each turbine will have an air chiller to enhance power output during hot weather.

The HRSGs will be linked to a steam turbine with a generating capacity of 130 MW which will be used as demand becomes sufficient. Total facility generating capacity will be 310 MW.

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

Each LM6000 has a nominal output of 45 MW at base conditions of 11°F, with an LHV of 406 MMBTU/hr (450 MMBTUH based on HHV). These turbines will employ lean pre-mix NO_x combustion technology. A typical dry low-NO_x burner for a turbine consists of one diffusion flame pilot nozzle surrounded by several equally spaced premix flame main nozzles. The formation of NO_x is influenced by how much gas is burned in the pilot flame and how much is burned in the surrounding combustor nozzles. The multi-nozzle design spreads the combustion volume into a wider, cooler, less concentrated flame. Typically, for natural gas fuel, approximately 17% by volume of the total gas flow is sent through the pilot nozzle. Other than startup, shutdown, and malfunctions, the turbine will be operated at sufficient 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. However, elevated levels of NO_x and CO can result during cold startups and/or in the "diffusion" mode. Plant operation will be such that the turbine combustion system will be expeditiously brought into the pre-mix operation mode after light-off.

Each duct burner will fire only natural gas at up to 185 MMBTU/hr. There will be four primary stacks for exhausts from each combined cycle unit. Each stack will be 105 feet above grade with a diameter of 9 feet. The maximum load stack temperature is 226°F with a velocity of 64.5 fps. The facility may construct the gas turbines first and run in simple-cycle mode for a period of time. In this case, emissions will be from the gas turbine exhaust stacks which are 85 feet above grade and 15 feet in diameter. The maximum load stack temperature is 761°F with a velocity of 55.0 fps.

The emergency generator is diesel-fueled and is rated at 7.3 MMBTU/hr heat input (750 kW output) and will include an associated 250-gallon diesel storage tank. The diesel fire pump is rated at 1.76 MMBTU/hr heat input (250 HP output) and will include an associated 250-gallon diesel storage tank. The generator will operate a maximum of 800 hrs/yr, and the fire pump a maximum of 500 hrs/yr. The fire pump will be an insignificant source for future Title V permitting.

Waste heat at the facility will be handled by two four-cell cooling towers and a six-cell cooling tower. They are mechanical draft, counterflow-type towers with associated liquid drift. This drift is a source of particulate emissions, caused by dissolved and suspended solids inherently contained within the liquid droplets. The water droplets evaporate, allowing the particulates to agglomerate. At worst-case, the cooling towers may operate continuously, or 8,760 hours per year. The two four-cell cooling towers each will have a total flow of 8,400 GPM. Based on a total dissolved solids content of the water of 8,000 ppm and a drift of 0.0005%, potential emissions of 0.17 lb/hr and 0.74 TPY are calculated. These two cooling towers will be considered insignificant sources for Title V purposes. For the six-cell cooling tower, a total flow of 94,638 GPM and total dissolved solids content of the water of 8,000 ppm equate to potential emissions of 3.78 lb/hr. These emissions units are considered trivial activities pursuant to Appendix J of OAC 252:100, but since PM emissions of 16.60 TPY are anticipated, the six-cell tower will be permitted as a significant source.

The facility contemplates installation of one or two emergency boilers. Total anticipated capacity will be 31 MMBTUH and total maximum operations will be 6,500 hours per year. The boiler(s) will be fueled with natural gas.

SUMMARY OF SIGNIFICANT EMISSION UNITS

Unit ID	Description	Capacity	Heat Input, MMBTUH HHV	Maximum Annual Hours of Operations
100	Fire Pump	250 HP	1.76	500
200	Emergency Generator	1,000 HP	7.3	800
300	Combustion Turbine No. 1	45 MW	450	8,760
301	Combustion Turbine No. 2	45 MW	450	8,760
302	Combustion Turbine No. 3	45 MW	450	8,760
303	Combustion Turbine No. 4	45 MW	450	8,760
400	HRSG No. 1	32.5 MW	185	8,500
401	HRSG No. 2	32.5 MW	185	8,500
402	HRSG No. 3	32.5 MW	185	8,500
403	HRSG No. 4	32.5 MW	185	8,500
500	Auxiliary Boiler(s)	31 MMBTUH	31	6,500
600	Cooling Tower 1	94,638 GPM	--	8,760
601	Cooling Tower 2	8,400 GPM	--	8,760
602	Cooling Tower 3	8,400 GPM	--	8,760

SECTION III. EMISSIONS AND SCOPE OF REVIEW

This project involves a number of emission points. Emissions are generated by combustion at the turbines, the duct burners, and to a much smaller extent the emergency generator and fire pump. Each HRSG stack exhausts combustion emissions from its duct burner and related turbine. Negligible emissions of VOC are expected from the diesel storage tanks.

Criteria Air Pollutants (CAPs)

The following tables show emissions based on best available data. Emission factors for the turbines and duct burners for NO_x, PM_{10}, VOC, and CO are based on manufacturer's data. Emissions of SO_2 are based on 0.0056 lbs SO_2 per MMBTU heat input (derived from a sulfur concentration of 2 grains per 100 SCF in natural gas fuel), higher heating value, from 40 CFR Part 75, Appendix D. The higher heating value of natural gas is taken to be 1,020 BTU/scf, and the ratio of HHV to LHV is 1.109.

The manufacturer's data for NO_x, PM_{10}, VOC, and CO are based on multiple operating scenarios. The first division is by temperature, including 11°F, 36°F, 59°F, 77°F, 95°F, and 100°F. The second division is by load, including 50%, 75%, and 100%. Short-term limits are based on maximum expected emissions at any condition with yearly limits based on 25 ppmdv NOx at nominal conditions for simple cycle operations. For combined cycle operations, the yearly NOx limit will be 5 ppmvd with up to 10 ppm ammonia slip.

<u>LM6000 Turbines and Duct Burners</u>

Pollutant	**Turbine Emission Factors**	**Each Gas Turbine**		**Duct Burner Emission Factor, lb/MMBTU** [2]	**Each Duct Burner**		**Each Combined Cycle Unit**	
		lbs/hr	**TPY**		**lbs/hr**	**TPY** [3]	**lbs/hr**	**TPY**
NO_x	25 ppm [1, 8]	41.00	71.83	0.08 lb/MMBTU 3.5 ppm [1,9]	2.96	12.58	11.16	48.49
SO_2	0.0056 lb/MMBTU	2.54	4.45	0.0056	1.04	4.42	3.58	15.55
PM_{10}	0.0088 lb/MMBTU[4]	3.97	6.96	0.0113[5]	2.09	8.88	6.06	26.27
VOC	0.0027 lb/MMBTU	1.20	2.10	0.035[7]	4.53	19.25	5.73	24.51
CO	40 ppm [6] 0.1311 lb/MMBTU	59.00	103.37	0.055	10.18	43.26	69.18	301.69
H_2SO_4	0.0022 lb/MMBTU	0.97	1.70	0.0013	0.24	1.02	1.21	5.27
NH_3	--	--	--	10 ppm [1,9]	--	--	8.25	35.92

[1] @ 15% O_2, dry-basis
[2] HHV of 1,020 BTU/SCF
[3] 12-month rolling total, 3,504 hours/year for gas turbines operating in simple cycle mode, 8,500 hours/year for duct burners, combined cycle gas turbines authorized up to 8,760 hours/year.
[4] PM emissions are approximately constant with varying loads, so the emission factors vary from 0.0159 lb/MMBTU at 50% load to 0.0088 lb/MMBTU at maximum load.
[5] Sum of sulfuric acid mist and soot emissions.
[6] 40 ppm is an annual average; worst-case CO emissions are 64 ppm at 11°F ambient temperature, 75% load.
[7] Maximum VOC emissions are predicted to be 4.53 lb/hr at 70% load.
[8] Simple cycle operations
[9] Combined cycle operations

Emissions from the fire pump are calculated using factors from AP-42 (10/96), Table 3.3-1 for uncontrolled diesel industrial engines smaller than 600 HP. Emissions from the emergency generator are calculated using factors from AP-42 (10/96), Table 3.4-1 for uncontrolled diesel industrial engines larger than 600 HP. The 750 kW (1,000 HP) generator is rated at 7.3 MMBTUH and will operate up to 800 hours per year. The fire pump is rated at 250 HP (1.76 MMBTUH) and is limited to 500 operating hours per year. Emissions from the associated diesel storage tanks are negligible.

Unit	**Pollutant**	**Factor (lb/MMBTU)**	**Emissions lb/hr**	**Emission TPY**
Fire Pump (1.76 MMBTUH)	NO_X	4.41	7.75	1.94
	CO	0.95	1.67	0.42
	SO_2*	0.05	0.09	0.02
	VOC **	0.36	0.63	0.16
	PM_{10}	0.31	0.55	0.14
Emergency Generator (7.3 MMBTUH)	NO_X	3.2	23.36	9.34
	CO	0.85	6.21	2.48
	SO_2*	0.05	0.35	0.15
	VOC **	0.09	0.66	0.26
	PM_{10}	0.10	0.73	0.29

* based on 0.05% by weight sulfur in fuel, part of the BACT.
**sum of exhaust plus crankcase VOC.

Emissions from the six-cell cooling tower were calculated assuming a drift ratio (ratio of lost water to total water input) of 0.001%, a total water input of 94,638 GPM, and total dissolved solids (TDS) content of 8,000 ppm. Combining six total cells yields 3.78 lbs/hr or 16.60 TPY of TSP. The application conservatively assumed all TSP was PM_{10}. The two smaller four-cell cooling towers were calculated assuming a drift ratio of 0.0005%, a total water input of 8,400 GPM each, and a total dissolved solids content of 8,000 ppm. Combining the four cells for each of the smaller cooling towers yields 0.17 lb/hr and 0.74 TPY of PM for each smaller cooling tower. EPRI's report entitled *User's Manual – Cooling Tower Plume Prediction,* states on page 4-1 that this particulate ranges in size between 20 and 30 micron, thus none of the TSP would be expected to be PM_{10}.

Emissions from the auxiliary boiler(s) are calculated using factors from AP-42 (7/98), Table 1.4-2 for small boilers (with a heat input less than 100 MMBTUH). The boiler(s) will be limited to 6,500 operating hours per year.

Unit	Pollutant	Factor (lb/MMBTU)	Emissions lb/hr	Emission TPY
Auxiliary Boiler(s)	NO_X	0.098	3.04	9.88
	CO	0.082	2.55	8.30
	SO_2*	0.0056	0.17	0.56
	VOC	0.0055	0.17	0.54
	PM_{10}	0.0076	0.23	0.75

* adjusted for 2 gr/100 SCF sulfur.

SUMMARY OF EMISSIONS

A. Simple-Cycle Operations

Emission Unit	Unit ID	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Fire Pump	100	0.55	0.14	0.09	0.02	7.75	1.94	0.63	0.16	1.67	0.42
Emergency Generator	200	0.73	0.29	0.35	0.15	23.36	9.34	0.66	0.26	6.21	2.48
Turbine No. 1	300	3.97	6.96	2.54	4.45	41.00	71.83	1.20	2.10	59.00	103.37
Turbine No. 2	301	3.97	6.96	2.54	4.45	41.00	71.83	1.20	2.10	59.00	103.37
Turbine No. 3	302	3.97	6.96	2.54	4.45	41.00	71.83	1.20	2.10	59.00	103.37
Turbine No. 4	303	3.97	6.96	2.54	4.45	41.00	71.83	1.20	2.10	59.00	103.37
Auxiliary Boiler(s)	500	0.23	0.75	0.17	0.56	3.04	9.88	0.17	0.54	2.55	8.30
Cooling Tower 1	600	3.78	16.60	--	--	--	--	--	--	--	--
Cooling Tower 2	601	0.17	0.74	--	--	--	--	--	--	--	--
Cooling Tower 3	602	0.17	0.74	--	--	--	--	--	--	--	--
TOTALS		21.51	47.10	10.77	18.53	198.15	308.48	6.26	9.36	246.43	424.68

B. Combined-Cycle Operations

Emission Unit	Unit ID	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Fire Pump	100	0.55	0.14	0.09	0.02	7.75	1.94	0.63	0.16	1.67	0.42
Emergency Generator	200	0.73	0.29	0.35	0.15	23.36	9.34	0.66	0.26	6.21	2.48
Turbine No. 1	300	3.97	17.39	2.54	11.13	8.20	35.92	1.20	5.26	59.00	258.42
Turbine No. 2	301	3.97	17.39	2.54	11.13	8.20	35.92	1.20	5.26	59.00	258.42
Turbine No. 3	302	3.97	17.39	2.54	11.13	8.20	35.92	1.20	5.26	59.00	258.42
Turbine No. 4	303	3.97	17.39	2.54	11.13	8.20	35.92	1.20	5.26	59.00	258.42
HRSG No. 1	400	2.09	8.88	1.04	4.42	2.96	12.58	4.53	19.25	10.18	43.26
HRSG No. 2	401	2.09	8.88	1.04	4.42	2.96	12.58	4.53	19.25	10.18	43.26
HRSG No. 3	402	2.09	8.88	1.04	4.42	2.96	12.58	4.53	19.25	10.18	43.26
HRSG No. 4	403	2.09	8.88	1.04	4.42	2.96	12.58	4.53	19.25	10.18	43.26
Auxiliary Boiler(s)	500	0.23	0.75	0.17	0.56	3.04	9.88	0.17	0.54	2.55	8.30
Cooling Tower 1	600	3.78	16.60	--	--	--	--	--	--	--	--
Cooling Tower 2	601	0.17	0.74	--	--	--	--	--	--	--	--
Cooling Tower 3	602	0.17	0.74	--	--	--	--	--	--	--	--
TOTALS		29.87	124.34	14.93	62.93	78.79	215.16	24.38	99.00	287.15	1217.9

* NOx emissions from the duct burners are incorporated into the turbine emissions.

Hazardous and Toxic Air Pollutants (HAPs & TAPs)

HAP emissions are shown in the following table and are based on AP-42 (4/00), Table 3.1-3; AP-42 (7/98), Table 1.4-3; and AP-42 (10/96), Tables 3.3-2 and 3.3-4. Estimates shown in the table represent the total emissions (both lbs/hr and TPY) from all units.

An emissions factor for sulfuric acid was developed using the following rationale: It was assumed that all fuel sulfur was converted to SO_2. An extremely conservative estimate was that initially 10% of SO_2 was converted to SO_3, then subsequently another 15% of SO_2 was converted to SO_3 in the duct burners. Of the SO_2 created in the duct burners, 15% there also was assumed to be converted to SO_3. All SO_3 was assumed to react with water and form H_2SO_4. The ratio of molecular weights of H_2SO_4 to SO_2 is 98/64, or 1.53. For every pound of SO_2 created, approximately 0.30 lb of H_2SO_4 is calculated by this method. More conventional emission factors show a 3% conversion, so the above method will overstate H_2SO_4 emissions somewhat.

Ammonia emissions were calculated based on a "slip" of 10 ppm at 15% oxygen.

Note that twothree HAPs/TACs (ammonia, formaldehyde and pentane) exceed their respective Category *de minimis* thresholds. Further discussion is found under OAC 252:100-41 in the Oklahoma Air Pollution Control Rules section of this memo. In addition, total HAPs equal 13.42 TPY, and neither HAP will exceed 10 TPY. Thus, the facility is a minor source for HAPs.

TOXIC / HAP EMISSIONS

Pollutant	Tox Class	C A S Number	Emissions		De Minimis		MAAC
			lb/hr	TPY	lb/hr	TPY	ug/m^3
1,3-butadiene*	A	106990	0.01	0.01	0.57	0.60	44
2-methyl naphthalene	C	1321944	0.01	0.01	5.6	6.0	1000
3-methyl chloranthrene	A	56495	0.01	0.01	0.57	0.6	NE
7,12-dimethyl benz-a-anthracene*	A	56564	0.01	0.01	0.57	0.60	NE
acetaldehyde*	B	75070	0.07	0.28	1.1	1.2	3600
acenaphthene*	A	83329	0.01	0.01	0.57	0.60	1
acenaphthalene*	A	208968	0.01	0.01	0.57	0.60	NE
acrolein*	A	107028	0.01	0.05	0.57	0.60	2
ammonia	C	7664417	33.00	143.68	5.60	6.0	1742
anthracene	A	1201217	0.01	0.01	0.57	0.60	1
benzo-a-anthracene*	A	56553	0.01	0.01	0.57	0.60	NE
benzene*	A	71432	0.03	0.09	0.57	0.60	32
benzo-a-pyrene*	A	50328	0.01	0.01	0.57	0.60	NE
benzo-b-fluoranthene*	A	205992	0.01	0.01	0.57	0.60	NE
benzo-(g,h,I) perylene*	A	191242	0.01	0.01	0.57	0.60	NE
benzo-k-fluoranthene*	A	207089	0.01	0.01	0.57	0.60	NE
butane	NS	106978	1.59	6.68	––	––	--
chrysene*	A	218019	0.01	0.01	0.57	0.60	1
dibenzo-a,h-anthracene*	A	53703	0.01	0.01	0.57	0.60	NE
dichlorobenzene	B	95501	0.01	0.01	1.1	1.2	6012
ethane	NS	74840	2.34	9.86	––	––	--
ethyl benzene*	C	100414	0.05	0.23	5.6	6.0	43427
fluoranthene*	C	206440	0.01	0.01	5.6	6.0	NE
fluorine*	A	86737	0.01	0.01	0.57	0.60	1
formaldehyde*	A	50000	1.21	5.25	0.57	0.60	12
hexane*	C	110543	1.36	5.73	5.6	6.0	17628
indeno-1,2,3,c,d-pyrene*	A	193395	0.01	0.01	0.57	0.60	NE
naphthalene*	B	91203	0.01	0.01	1.1	1.2	1000

Pollutant	Tox Class	C A S Number	Emissions		De Minimis		MAAC ug/m³
			lb/hr	TPY	lb/hr	TPY	
pentane	C	109660	1.97	8.27	5.6	6.0	35000
phenanthrene*	A	85018	0.01	0.01	0.57	0.60	1
PAH	A	---	0.01	0.02	0.57	0.60	NE
propylene	NS	115071	0.03	0.01	––	––	--
propylene oxide*	A	75569	0.05	0.21	0.57	0.60	500
propane	NS	74986	1.21	5.09	––	––	--
pyrene*	A	129000	0.01	0.01	0.57	0.60	1
toluene*	C	108883	0.22	0.94	5.6	6.0	37668
xylene*	C	1330207	0.11	0.46	5.6	6.0	43427
arsenic*	A	7440382	0.01	0.01	0.57	0.60	2
barium	B	7440393	0.01	0.04	1.1	1.2	10
beryllium*	A	7440417	0.01	0.01	0.57	0.60	0.02
cadmium*	A	7440439	0.01	0.01	0.57	0.60	0.5
chromium*	A	7440473	0.01	0.01	0.57	0.60	0.25
cobalt*	A	7440484	0.01	0.01	0.57	0.60	0.5
copper	B	7440508	0.01	0.01	1.1	1.2	4
manganese*	C	7439965	0.01	0.01	5.6	6.0	100
mercury*	A	7439976	0.01	0.01	0.57	0.60	0.5
molybdenum	C	7439987	0.01	0.01	5.6	6.0	1000
nickel*	A	7440020	0.01	0.02	0.57	0.60	0.15
selenium*	C	7782492	0.01	0.01	5.6	6.0	20
vanadium	A	7440622	0.01	0.02	0.57	0.60	0.5
zinc	C	1314132	0.07	0.29	5.6	6.0	500

* Total HAP emissions = 13.42 TPY.

As shown in the table following, the proposed facility triggers the 100 TPY PSD threshold limit for NO_x and CO, and will have potential emissions above the PSD significance levels for SO_2, H_2SO_4, VOC and PM_{10}. These pollutants are reviewed below.

A BACT analysis is required for all pollutants emitted in PSD-significant quantities. The BACT review follows the "top-down" methodology. Reviewed are the most stringent controls for each applicable pollutant based on RACT/BACT/LAER Clearinghouse and vendor information. Cost estimates of control equipment were based on "*OAQPS Control Cost Manual,*" (EPA, 1997).

Pollutant	**NO_X**	**CO**	**SO_2**	**VOC**	**PM_{10}**	**H_2SO_4**
Simple Cycle Emissions	308.48	424.68	18.53	9.36	47.10	6.80
Combined Cycle Emissions	215.16	1217.9	62.93	99.00	124.34	21.08
PSD Significance Level	40	100	40	40	15	7
PSD Review Required?	Yes	Yes	Yes	Yes	Yes	Yes

Other pollutants for which PSD significance levels are established (asbestos, vinyl chloride, lead, fluorides, H_2S, and TRS) are not expected to be emitted in other than negligible amounts from this type of facility. Sources to be considered are the turbines, HRSGs, auxiliary boiler(s), cooling towers, emergency generator and fire pump. Each turbine and its associated duct burner are 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 impacts

SECTION IV. BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

The emission units for which a BACT analysis is required include the combustion turbines, auxiliary boiler(s), 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 BACT determinations for similar facilities, and vendor-supplied information.

ELECTRIC POWER PLANT PERMITS ISSUED BY AQD SINCE JANUARY 1, 2000

Permit No.	**Company**	**Facility**	**Issuance Date**	Equipment
99-028-C (PSD)	Calpine Corp.	Oneta	1/21/00	four 168 MW turbines
				four 200 MMBTUH duct burners
				100 kW diesel emergency generator
				260 HP water pump
99-213-C (PSD)	Duke Energy	Newcastle	1/19/00	two 170 MW turbines
				22 MMBTUH auxiliary boiler
				400 HP diesel water pump
2000-116-C (PSD)	Energetix	Thunderbird	5/17/01	three 230 MW turbines
				three 427 MMBTUH duct burners
				20 MMBTUH auxiliary boiler
				1,340 HP diesel emergency generator
2000-103-C (PSD) (M-1)	Kiowa Partners	Kiamichi	5/01/01	four 182 MW turbines
				four 650 MMBTUH duct burners
				28 MMBTUH auxiliary boiler
				1,100 kW emergency generator
				270 HP diesel water pump
2000-151-C (PSD)	KM Power Co.	Pittsburg	5/03/01	six 55 MW turbines
				one 119 MW turbine
				six 370 MMBTUH duct burners
				900 kW emergency diesel generator
				250 HP diesel water pump
99-312-C (PSD)	ONEOK	Edmond	5/11/00	four 80 MW turbines
				750 kW diesel emergency generator
2000-115-C (PSD)	Smith Cogeneration	Pocola	5/04/01	four 172 MW turbines
				four 577 MMBTUH duct burners
				two 48 MMBTUH auxiliary generators
				1,100 kW emergency generator
				250 HP diesel water pump
2000-273-C (PSD)	WFEC Genco.	Anadarko	11/30/00	two 47 MW turbines

Of these, only the turbines at KM Power and WFEC Genco are comparable in size to the 45 MW combustion turbines proposed for Mustang. The NOx BACT for each of these was determined to be 25 ppm @ 15% oxygen.

If the proposed BACT is equivalent to the most stringent emission limit, no further analysis is necessary. However, if the most stringent emission limit is not selected, additional analyses are required.

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

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

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

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

The following potential control systems were considered in the BACT analysis for the combustion turbines with duct burners, the emergency diesel generator, the diesel fire pump, and the cooling towers.

AVAILABLE CONTROL OPTIONS

Pollutant	Unit	Emissions Limit Range, (ppmvd)	Control Technique
NO_X	Turbines, Duct Burners	2 – 2.5	SCONOx™
		3 – 5	Catalytic (flameless) combustion (XONON™)
		3 – 5*	Selective catalytic reduction (SCR) plus water injection or low-NOx combustor
		5 – 12.5	Selective catalytic reduction (SCR) plus water/ steam injection or advanced low-NOx combustor
		9 – 25	Dry low NO_x combustor
		25 – 35	Water or steam injection
	Diesel Generator, Fire Pump	3.2 – 4.41 lb/MMBTU	Good combustion practices/design
	Auxiliary Boiler(s)	0.10 lb/MMBTU	Good combustion practices/design
TSP/PM_{10}	Turbines, Duct Burners	0.010–0.0117 lb/MMBTU	Low-ash fuels
	Diesel Generator, Fire Pump	0.10 – 0.36 lb/MMBTU	Low-ash fuels
	Cooling towers	0.001% drift	Drift eliminators/design
	Auxiliary Boiler(s)	0.0076 lb/MMBTU	Low-ash fuels
CO	Turbines, Duct Burners	2 – 6	Oxidation catalyst
		10 – 25	Good combustion practices/design
	Diesel Generator, Fire Pump	25-50	Good combustion practices/design
	Auxiliary Boiler(s)	0.084 lb/MMBTU	Good combustion practices/design
VOC	Turbines, Duct Burners	2-6 ppm	Oxidation catalyst (side effect from CO control)
	Diesel Generator, Fire Pump	0.09 – 0.36 lb/MMBTU	Good combustion practices/design
	Auxiliary Boiler(s)	0.0055 lb/MMBTU	Good combustion practices/design
SO_2	Turbines, Duct Burners, Auxiliary Boiler	0.0056 lb/MMBTU	Low-sulfur fuel
	Diesel Generator, Fire Pump	0.05% sulfur	Low-sulfur fuel

* The application listed 5-9 ppm for SCR; other sources list 3-5 ppm.

1. IDENTIFICATION OF CONTROL TECHNIQUES

a) Nitrogen Oxide (NO_x) Control Techniques

Combustion Turbines and Duct Burners

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

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

Since the formation of NO_X is largely dependent on thermal NO_X, several control technologies employ techniques to reduce the precursors of NO_X formation or use catalysts to treat the post combustion emissions. There are three types of emission controls for natural gas-fired turbines. The least effective are wet controls, which use steam or water injected into the combustion zone to reduce the ambient flame temperature, thus controlling NO_X formation. Intermediate are dry controls that use advanced combustor design to suppress NO_X formation. Most effective are post-combustion catalytic controls that selectively or non-selectively reduce NO_X. For simple cycle operations, the operator proposes the use of the best combustion control technologies available for the model of turbine proposed. These are dry low NO_X (DLN) combustion for the LM6000 turbines and low-NOx burners for the duct burners. For combined cycle operations, this applicant proposes the use of SCR (or equivalent control).

SCONOx^{TM}

SCONOx^{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.

SCONOx^{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 which are emitted from the stack.

A typical arrangement has ten or fifteen sections of catalyst, although the number can vary on each system depending on size and other special design requirements. At any given time eighty percent of these sections are in the oxidation/absorption cycle and twenty percent are in the regeneration cycle.

Ideally suited to both new and retrofit applications, the SCONOx^{TM} system can operate effectively at temperatures ranging from 300 to 700°F and does not limit gas turbine performance. A SCONOx^{TM} unit can be installed at the back-end of the Heat Recovery Steam Generator within the same envelope reserved for an SCR system.

On October 30, 2000, Air Quality received a letter from EPA Region VI informing us it was their view that SCONOx^{TM} is a technically feasible and commercially available control option for NO_x emissions for large combined-cycle turbine projects.

Catalytic (Flameless) Combustion (XONON^{TM})

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^{TM}. The XONON^{TM} 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^{TM} 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.

Selective Catalytic Reduction (SCR)

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 gets too high, the catalyst may begin to decompose. Turbine exhaust gas is generally in excess of 1000°F. HRSGs 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 1100°F, are an option. Selective catalytic reduction can typically achieve NO_x emission reduction 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. The normal ammonia slip is 10-20 ppm, but recently the vendors have been guaranteeing less than 10 ppm at locations at California. It is concurred that SCR (or equivalent control) at the gas turbines and good combustion control at the duct burners (a level equivalent to low-NO_x burners) satisfies BACT requirements for combined cycle operations of this facility.

Lean-Premix Technology

Turbine manufacturers have developed processes that use air as a diluent to reduce combustion flame temperatures, and 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.

The burner, or combustor, is the space inside the gas turbine where fuel and compressed air are burned. The combustion chamber can take the shape of a long cylinder, an axially-centered ring of long cylinders (can-annular combustor), an annulus located behind the compressor and in front of the gas turbine (annular combustor), or a vertical silo.

Conventional combustors are diffusion controlled. This means fuel and air are injected into the combustor separately and mix in small, localized zones. The zones burn hot and produce more NO_x. In contrast, lean-premix combustors minimize combustion temperatures by providing a lean-premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The lower temperatures reduce NO_x formation. However, because the mix is so lean, the flame must be stabilized with a pilot flame. Some lean-premix combustors can achieve emissions of as low as 9 ppmvd NO_x at 15 percent oxygen (approximately 94 percent control) on larger turbines.

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 loads. 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. The applicant has proposed DLN in the gas turbines and good combustion control in the duct burners as BACT. These controls have no adverse environmental or energy impacts. AQD concurs that DLN combustion at the gas turbines is acceptable as BACT.

Steam/Water Injection

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 of less than 25 ppmvd NO_x at 15 percent oxygen (approximately 82 percent control).

Combustor geometry, injection nozzle design, and the fuel nitrogen content can affect diluent injection performance. Water or steam must be injected into the combustor so that a homogeneous mixture is created. Non-uniform mixing of water and fuel creates localized “hot spots” in the combustor that generates NO_x emissions. Increased NO_x emissions require more diluent injection to meet a specified level of emission. When diluent injection is increased, dynamic pressure oscillations in the combustor increase. Dynamic pressure oscillations can create noise and increase the wear and tear and required maintenance on the equipment. Continued increase of diluent injection will eventually lead to combustor flame instability and emission increases of CO and unburned hydrocarbons due to incomplete combustion.

Water is a better heat sink than steam; therefore more steam is required to reach a particular level of NO_x emission. However, newer gas turbines usually apply steam injection. Steam injection is generally a better alternative since it does not increase the heat rate as much as water, carbon monoxide emissions are increased a smaller amount, pressure oscillations are less severe, and maintenance is reduced.

Selective Non-Catalytic Reduction (SNCR), Thermal DeNO$_X$™

SNCR is based on the principle that ammonia or urea react with NO_x in the flue gas to form N_2 and H_2O. In practice, the technology has been applied in boilers by injecting ammonia into the high temperature (e.g., 1,300°F - 2,000°F) region of the exhaust stream. Incorrect location of injection points, insufficient residence times and miscalibration of injection rates may result in excess emissions of ammonia (“ammonia slip”), a hazardous air pollutant (HAP). When successfully applied, SNCR has shown reduction in NO_x emissions from boilers of 35 to 60 percent.

Thermal DeNO$_x$ is a high temperature selective non-catalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal DeNO$_x$ requires the exhaust temperature to be above 1,800°F.

Auxiliary Boiler(s)

An uncontrolled NO_X emission of 0.10 lbs/MMBTU for the auxiliary boiler(s) is proposed as BACT. This emission rate is equivalent to low-NOx burner design. A review of the RBLC indicates that this type of equipment has not been required to install additional NO_X controls. The proposed BACT has no adverse environmental or energy impacts. It is agreed that combustion controls are acceptable as BACT.

Emergency Diesel Generator And Diesel Fire Pump

An uncontrolled NO_X emission of 3.2 lbs/MMBTU for the emergency diesel generator and 4.41 lbs/MMBTU for the diesel fire pump is based on engine design 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. It is agreed that engine design and a limitation on hours of operation is acceptable as BACT.

b) Carbon Monoxide (CO) Control Techniques

Combustion Turbines / Duct Burners

Historically, two forms of CO emission controls have been used on gas turbines. Combustion controls were used in the mid-1980s to achieve emission levels down to 25 ppmvd CO at 15 percent oxygen. In the late 1980s, oxidation catalysts were used on larger gas turbine cogeneration units. Oxidation catalysts can achieve 80 to 90 percent control of CO emissions. Although oxidation catalysts have been used on simple-cycle gas turbines, the use of oxidation catalysts have been largely limited to cogeneration and combined-cycle gas turbines. High temperature oxidation catalysts are available, and simple-cycle gas turbines with lower flue-gas temperatures have been controlled with high temperature oxidation catalysts.

Secondary combustion is a recognized technique of reducing CO emissions, and duct burners will provide secondary combustion. However, by convention, the duct burners are treated as separate emission units for the purposes of BACT analysis. Oxidation catalysts can achieve 80 to 90 percent control of CO emissions. High temperature oxidation catalysts are available, and simple-cycle gas turbines with lower flue-gas temperatures have been controlled with high temperature oxidation catalysts.

Since oxidation catalysts will control other pollutants, the cost can be spread among them. An annualized cost is estimated at $637,664 per combined cycle unit. The oxidation catalyst will eliminate approximately 241.4 TPY CO, 9.8 TPY VOC, and 0.5 TPY formaldehyde (also a VOC). These costs and results yield an average of $2,538 per ton controlled, which is excessive.

The application proposes combustion controls achieving 40 ppm CO (annual average) as BACT. A check of recent BACT determinations showed that this is consistent with other determinations nationally. Oxidation catalysts are only rarely required.

Auxiliary Boiler(s)

An uncontrolled CO emission of 0.084 lbs/MMBTU for the auxiliary boiler(s) is proposed as BACT. A review of the RBLC indicates that this type of equipment has not been required to install additional CO controls because of relatively small size. The proposed BACT has no adverse environmental or energy impacts. It is agreed that combustion control to 0.084 lb/MMBTU is acceptable as BACT.

Emergency Diesel Generator And Diesel Fire Pump

An uncontrolled CO emission of 0.85 lbs/MMBTU for the emergency diesel generator and 0.95 lbs/MMBTU for the diesel fire pump is based on engine design and is proposed as BACT. A review of the RBLC indicates that this type of equipment has not been required to install additional CO controls because of intermittent operation. The proposed BACT has no adverse environmental or energy impacts. It is agreed that engine design is acceptable as BACT.

c) VOC Control Techniques

Since formaldehyde is a VOC, and BACT is required for formaldehyde emissions, this analysis suffices for a formaldehyde BACT analysis.

<u>Combustion Turbines / Duct Burners</u>

The most stringent VOC control level for gas turbines has been achieved through catalytic oxidation for CO control. According to the list of turbines in the RACT/BACT/LAER Clearinghouse with limits on VOC, oxidation catalyst systems represent BACT for VOC control in only four of 36 facilities listed.

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. These conditions are descriptive of the dry low-NOx combustion system proposed as BACT for NOx emissions.

Secondary combustion is an option for VOC emissions control. The facility is designed with duct burners which would provide that secondary combustion. However, the facility may be operated without duct burners.

The most stringent VOC control level for gas turbines has been achieved through catalytic oxidation for VOC emissions control. According to the list of turbines in the RACT/BACT/LAER Clearinghouse with limits on VOC, oxidation catalyst systems represent BACT for VOC control in only 11% of the 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.

The application proposes combustion controls achieving 0.015 lbs/MMBTU VOC as BACT from the duct burners. Secondary combustion is a recognized technique of reducing VOC emissions, and duct burners will provide secondary combustion. However, by convention, the duct burners are treated as separate emission units for the purposes of BACT analysis. Oxidation catalysts can achieve greater than 95% percent control of VOC emissions. High temperature oxidation catalysts are available, and simple-cycle gas turbines with lower flue-gas temperatures have been controlled with high temperature oxidation catalysts.

The applicant proposes good combustion control as BACT for both the gas turbines and duct burners. Duct burners will not necessarily be installed (or operated if installed). It is concurred that good combustion control is acceptable as BACT for the gas turbines and duct burners.

Auxiliary Boiler(s)

An uncontrolled VOC emission of 0.0055 lbs/MMBTU for the auxiliary boiler(s) is proposed as BACT. A review of the RBLC indicates that this type of equipment has not been required to install additional VOC controls, presumably because of small size and low emission rates. The proposed BACT has no adverse environmental or energy impacts. DEQ agrees that combustion control to 0.0055 lbs/MMBTU is acceptable as BACT.

Emergency Diesel Generator And Diesel Fire Pump

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

d) PM and PM_{10} Control Techniques

There are numerous potential control technologies for PM/PM_{10} emissions: baghouses, electrostatic precipitators, wet scrubbers, cyclones, and secondary combustors. A check of EPA's RBLC did not show these controls required for any gas-fired turbine, boiler, or duct burner; or for any distillate fuel engine. Since this database showed that these controls had already been eliminated from similar sources nationally, and considering that even LAER determinations were considered, AQD concurred that the analysis was acceptable.

Combustion Turbines, Duct Burners, and Auxiliary Boiler(s)

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 0.007 lbs/MMBTU from the turbines with duct burner firing. Based on the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, there are no BACT precedents that have included an add-on TSP/PM_{10} control requirement for natural gas-fired combustion turbines. Therefore, BACT for PM_{10} emissions from the combustion turbines is proposed to be the use of a no-ash fuel (natural gas) 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.

Emergency Diesel Generator And Diesel Fire Pump

These units, like the turbines, emit particulates consisting of ash in the fuel and residual carbon and hydrocarbons caused from incomplete combustion. The applicant's review of RBLC shows that good combustion control and/or good engine design is the most stringent requirement for this application.

The application proposes the use of distillate fuel for these units. Distillate fuel will have minimal ash content.

It is agreed that distillate fuel and good engine design are acceptable as BACT, without further analysis.

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. Therefore, the use of drift eliminators to attain a total emission rate of 3.78 lbs/hr is proposed as BACT for the six-cell cooling tower particulate emissions, without further analysis. The two smaller four-cell cooling towers will also use drift eliminators to achieve a total emission rate of 0.17 lb/hr each, which is also acceptable as BACT without further analysis. The proposed BACT will not have any adverse environmental or energy impacts.

e) SO_2 / H_2SO_4 Control Techniques

Combustion Turbines, Duct Burners, and Auxiliary Boiler(s)

Since H_2SO_4 emissions result from creation of SO_2, control of H_2SO_4 emissions is dependent on control of SO_2. A baseline for SO_2 emissions from the combustion turbines would be represented by the NSPS Subpart GG limitation of 0.8% by weight sulfur in fuels. Since the duct burners and auxiliary boiler(s) will use the same fuel supply, the 0.8% by weight level also represents a baseline of SO_2 emissions from those units. (For natural gas fuel, a limitation of 0.8% by weight is equivalent to an emission level of 0.14 lbs/MMBTU, which is lower than the limitation of OAC 252:100-31 of 0.2 lb/MMBTU.) The proposed limitation, 2 grains sulfur per 100 SCF natural gas, is equivalent to a level of 34 ppm by weight. This represents 99.2% reduction from the baseline.

There are numerous add-on control technologies available for SO_2. However, these are intended primarily for coal-fired units where SO_2 concentrations are one to two orders of magnitude above concentrations anticipated resulting from sweet natural gas combustion.

A limitation of sulfur content of 2 grains per 100 SCF sulfur is acceptable as BACT for SO_2 emissions from the large units.

Emergency Diesel Generator And Diesel Fire Pump

The applicant proposes BACT for SO_2 emissions from the stationary engines to be distillate fuel with 0.05% sulfur. This level is equivalent to road diesel sulfur, and the lowest sulfur distillate fuel normally available.

The two units are too small to consider add-on controls for SO_2.

Distillate fuel with 0.05% sulfur will have SO_2 emissions of approximately 0.05 lb/MMBTU. This represents a 94% reduction from the applicable limit and baseline of 0.8 lb/MMBTU.

2. TECHNICAL FEASIBILITY OF THE CONTROL TECHNIQUES

a) Nitrogen Oxide (NO_x) Control Techniques

Combustion Turbines and Duct Burners

SCONOx™

ABB Alstom Power, as of December 1999, offered SCONOx™, 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, EPA Region VI, in a letter dated October 20, 2000, stated that the Region now considers SCONOx™ 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.

XONON^{TM}

There is currently one field installation of the XONON^{TM} 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. Catalytical Combustion Systems (manufacturer of XONON^{TM}) has a collaborative commercialization agreement with General Electric Power Systems, committing to the development of XONON^{TM}. In conjunction with General Electric Power systems, the XONON^{TM} 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.

This control technique is currently in use at only one location at Schenectady, New York. It is not offered by GE or other large turbine vendor. It cannot, therefore, be considered an “available” control technology.

Selective Catalytic Reduction (SCR)

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% oxygen. However, levels as low as 2 ppmvd at 15 % 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 % oxygen be established in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip.

Lean-Premix Technology

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 about 9 to 42 ppmvd NO_x at 15 percent oxygen (approximately 94 percent control). The level of NOx control depends on the size of the turbine; the turbines in question are relatively small turbines, and therefore have relatively high NOx emissions compared to larger turbines such as Frame 7 models.

Steam/Water Injection

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).

Selective Non-Catalytic Reduction (SNCR), Thermal DeNO$_X$^{TM}

The only known commercial applications of Thermal DeNO$_X$^{TM} are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800^{o}F. There are no known applications on or experience with combustion turbines. Temperatures of 1,800^{o}F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased. This option has not been demonstrated on CTs. Thus, this control technology is not considered technically feasible and will be precluded from further consideration in this BACT analysis.

Tandem Approaches

While each type of control discussed above results in a particular level of NO_x emissions, the potential for further reducing emissions can be achieved by applying a tandem approach, using controls in combination. Common NO_x control combinations currently in use include water or steam injection with SCR, lean-premix combustors with SCR, and water injection with SCONOx^{TM}. Where present, there is also the potential to control NO_x from duct burners through burner combustion controls. The combination of duct burner, gas turbine combustion, and add-on controls has the potential to reduce NO_x emissions to very low levels.

Levels as low as 2 ppmvd NO_x have been seen in several states for permits that require a combination of lean-premix combustors with SCR. Levels as low as 3.5 ppmvd NO_x have been seen in permits that require a combination of water or steam injection with lean-premix combustors with SCR, and 6 ppmvd for a combination of water injection with SCR.

b) Carbon Monoxide (CO) Control Techniques

Combustion Turbines and Duct Burners

Historically, most PSD-BACT determinations for CO required good combustion practices (i.e., no post-combustion controls). More recent permits have required limits as low as 2.0 ppmvd, with a typical range of about 9 to 25 ppmvd. In some cases, facilities with the lower limits were located in non-attainment areas, and an oxidation catalyst was proposed for the additional purpose of limiting VOC emissions to below the non-attainment area major source threshold level.

3. CONTROL TECHNOLOGY EFFECTIVENESS AND IMPACTS

BACT for NO_x, CO, PM and VOC for the auxiliary boiler(s), diesel generator and fire pump; BACT for PM for the cooling towers; and BACT for PM and VOC for the turbines and duct burners were previously identified. Thus, further analysis of the control effectiveness, economics, energy, and environmental impacts is not provided for these pollutants and sources.

The following tables provide information sufficient to document the control effectiveness, economics, energy, and environmental impacts associated with control of NO_x and CO for the turbines and duct burners. Baseline emissions for the turbines and duct burners are also shown. Note that the analysis was performed on a unit (turbine and duct burner) basis.

LM6000 Turbines

As discussed previously, SCONOx™ provides the lowest level of NO_x emissions. The high cost per emission reduction of this control technology is cost-prohibitive for aeroderivative turbines that operate with lower annual capacity factors and mass emission rates.

Based on incremental NOx emission reductions of 218 TPY per combined cycle unit and annualized costs of $2.6 million, control costs of $11,265 per ton NOx are calculated. Therefore, it is ruled out as a control option.

The next most effective control technology for NO_x is a combination of steam injection and SCR to 3.5 ppm, followed by SCR alone. SCR will result in a somewhat lower level of emissions reductions (151 TPY per combined cycle unit). However, the annualized cost of the 151 TPY reduction is $1.6 million, or $10,776 per ton. Therefore, both SCR and the combination are ruled out as a control option. The applicant, however, has committed to install SCR (or equivalent control) to the gas turbines at the time the facility begins combined cycle operations.

DLN technology alone is considered an equivalent control when compared to steam injection. General Electric will guarantee 25 ppm of NO_x for the LM6000 DLN technology as compared to a 22-ppm level attainable with steam injection. The 22-ppm NO_x abatement level is the lowest guarantee offered by GE for the LM6000 aeroderivative turbine.

EPA's RBLC showed 53 recent determinations for NOx emissions from this type of turbine. Sixteen of these were for dry low-NOx combustors. Most of the other determinations were for roughly equivalent levels of controls (25 ppm), particularly for turbines in the size range of the turbines in question. The 25 ppm BACT level is comparable to other recent BACT determinations locally and nationally for 45 MW combustion turbines.

Since no other control options (other than CO oxidation) are available for CO control, BACT is selected as good combustion practices/design such that the following limitations are met:

A 1206.6 TPY cap (12-month rolling total) over all four turbines and duct burners is based on a CO exhaust concentration from the LM6000 turbines of 40 ppmvd @ 15% O_2 (annual basis).

Control Technology Effectiveness and Impact Summary for NO_x BACT Determination (Four LM6000s + Duct Burners)

Control Alternative	NOx Emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Average Cost ($/ton)	Adverse Environmental Impacts?
SCONOX	218	7,486,367	2,459,915	11,265	yes [a]
SCR	151	1,659,760	1,635,176	10,776	yes [b]
		--	--	--	

[a] Based on a 6 year "typical" catalyst life
[b] Primarily from the emissions of ammonia. These can be minimized with proper system design and operation. There is also a potential for increased particulate emissions from formation of secondary ammonia compounds—however, this is most likely minimal. SCR 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, this is not likely to be substantial.

Control Technology Effectiveness and Impact Summary for CO BACT Determination (Four LM6000s + Duct Burners)

Control Alternative	CO Emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Average Cost ($/ton)	Adverse Environmental Impacts?
Oxidation Catalyst	241.4	1,353,247	656,354	$2,538	yes [a]

[a] Allocated over both CO and VOC emissions.
[b] An oxidation catalyst results in the generation of spent vanadium pentoxide catalyst, which is classified as a hazardous waste.

B. CASE-BY-CASE MACT DETERMINATION

As previously noted in the emissions section, this facility is a minor source of HAPs (less than the 10/25 TPY thresholds), and thus a 112g case-by-case MACT determination for Hazardous Air Pollutants is not required.

SECTION V. AIR QUALITY IMPACTS

Potential NO_x and PM_{10} emissions are greater than the major source threshold of 100 TPY, and the proposed facility is considered to be a major stationary source of these pollutants. Therefore, the significant emission rate threshold of 40 TPY applies to VOC and SO_2 emissions from the plant. Although VOC emissions exceed 40 TPY, a demonstration of compliance with the NAAQS and PSD increments is not required because total VOC emissions are less than 100 TPY, pursuant to Table C-4 of the *New Source Review Workshop Manual.*

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

Modeling Procedures

A preliminary analysis was conducted to determine if NO_2, CO, SO_2, and PM_{10} emissions from the proposed source would result in off-site ambient impacts at levels greater than the significant ambient impact levels (SAIL) and/or the significant monitoring thresholds (SMT). For NO_2, the TPY limit was modeled, consistent with the averaging period. For CO, the lbs/hr limit was modeled. Combined-cycle operation is worst-case and was modeled because there are more emissions due to the HRSG than simple-cycle operation. Modeling assumed DLN control for combined cycle operations. Thus the modeling is very conservative since the applicant has agreed to additional controls at the time combined cycle operations are initiated. The SAIL and SMT for these pollutants are presented in the table below.

Pollutant	Averaging Period	Maximum Impacts (ug/m^3)	Significant Ambient Impact Limit (ug/m^3)	Monitoring Level of Significance (ug/m^3)
NO_2	annual	2.98	1	14
CO	1-hour	64.3	2,000	---
	8-hour	151.8	500	575
PM_{10}	24-hour	4.37	5	10
	annual	1.00	1	---
SO_2	3-hour	2.7	25	---
	24-hour	1.4	5	13
	annual	0.2	1	---

Impacts of NO_2 (annual average) are expected to exceed the SAIL, necessitating full impact analyses for this pollutant.

The full impact analysis consists of separate analyses for demonstrating compliance with the NAAQS and PSD increments. Both analyses require the development of emission inventories of nearby sources. Nearby sources are defined as any point source expected to cause a significant concentration gradient within the significant impact area (SIA).

There are two steps required to determine which facilities qualify as "nearby facilities." First, the region in which all sources must be initially classified as nearby sources must be defined. This region extends to 50 kilometers beyond the largest pollutant-specific SIA. A pollutant-specific SIA is the region within which the pollutant impacts are expected to exceed the SAIL. In this case, the NO_x SIA extends approximately 10.24 kilometers from the center of the facility (value determined from dispersion modeling). All facilities that emit the pollutant for which the full analysis is being performed and fall within a 50-kilometer radius of the pollutant-specific SIA are to be considered for inclusion in the modeling analysis. Therefore, for this analysis, all sources of NO_x within 60.24 kilometers of the facility are to be considered nearby sources unless they are otherwise disqualified. PM_{10}, SO_2 and CO emissions do not exceed the SAIL level, therefore an SIA is not triggered.

The second step in determining nearby sources requires calculating a ratio of the total facility emissions to the distance from the proposed facility. Oklahoma DEQ-AQD has issued guidance stating that use of the "Louisiana 20-D Rule" is acceptable for eliminating nearby sources. According to the guidance document, "when a nearby source's emissions (TPY) are less than 20 times the distance between the nearby source and the source in question (in kilometers), that source may be designated a background source and not modeled." Of the sources provided by ODEQ as potential nearby sources, seven sources of NO_x were modeled: OG&E Mustang Power Plant, OG&E Horseshoe Lake Power Plant, ONEOK Logan Plant, PowerSmith Cogeneration Plant, Energetix Arcadia Power Plant, Duke Energy McClain (Newcastle) Power Plant, and Energetix Thunderbird Power Plant.

Estimated background concentrations for those pollutants and averaging periods requiring a full impact analysis were provided in the application. Background pollutant concentrations are taken from monitoring stations in Oklahoma City, including 10^{th} Street and Stonewall Ave., (Oklahoma Department of Public Health building, approximately 20 miles east of the proposed facility) for NOx concentrations. These stations are considered to provide conservative background concentrations for the proposed facility.

Source Representation

The *Guideline on Air Quality Models* (GAQM, Table 9.2, Attachment W to 40 CFR Part 51), requires that short-term impacts from combustion sources subject to the PSD regulations be evaluated for maximum design capacity as well as for any normal operating condition that can lead to higher ambient impacts due to changes in source parameters. The GAQM also requires that annual impacts for these sources be evaluated at maximum design capacity. Short-term impacts of CO, PM_{10}, and SO_2 were assessed for various load conditions throughout the normal operating range of the turbines (i.e., 100, 75, and 50 percent loads). The hourly emission rates of CO, PM_{10}, and SO_2 were held constant while other source parameters were varied with the turbine load. Operating all turbines at a 75 percent load was determined as the worst-case load condition for CO, PM_{10}, and SO_2.

The maximum load scenario is defined as all turbines/duct burners operating at 100 percent load concurrently with the emergency diesel generator and cooling towers also operating at 100 percent capacity. The worst-case operating scenario for CO, PM_{10}, and SO_2 (determined by the ISCST3 screening mode analysis) is defined as LM6000s operating at 75 percent load (with full duct firing) and the emergency generator, fire pump, and auxiliary boilers all operating 100 percent capacity.

Dispersion Models and Inputs

The air quality modeling analyses employed the latest versions of USEPA's Industrial Source Complex Short-Term (ISCST3) dispersion model to determine ambient concentrations of NO_x, CO, PM_{10}, and SO_2 at and beyond the facility fence line. The ISCST3 model was used to determine impacts at a discrete set of off-site receptors and to identify the worst-case (highest impact) load scenarios for the ISC3 modeling. The models and associated input options are presented in the following sections.

<u>ISC3 Model</u>

The ISC3 model consists of two programs: a short-term model (ISCST3) and a long-term model (ISCLT3). The difference in these programs is that the ISCST3 program utilizes an hourly meteorological database, while ISCLT3 is a sector-averaged program using a frequency of occurrence based on categories of wind speed, wind direction, and atmospheric stability. The ISCST3 model was used for all pollutants. The default options selected are given below:

Model Input Options

1. The regulatory default options:

   a) Stack-tip downwash (except for Schulman-Scire downwash).
   b) Buoyancy-induced dispersion (except for Schulman-Scire downwash).
   c) No gradual plume rise.
   d) Calms processing routine.
   e) Default wind speed profile exponents.
   f) Default vertical potential temperature gradients.
   g) Upper-bound concentration estimates for sources influenced by building downwash from super-squat buildings.
2. Rural dispersion parameters (see below).
3. Building downwash parameters (see following).

Land Classification

Land use within three kilometers of the proposed site was classified according to the method developed by Auer (1978) using the most recent version of the United States Geological Survey (USGS) 7.5-minute topographic maps for the Kiowa quadrangle. Results of the Auer analysis are shown below:

URBAN LAND USE WITHIN 3 KILOMETERS OF THE SITE

Type	Land Use	Percentage of Area
I1	Heavy industrial	2%
I2	Light-moderate industrial	5%
C1	Commercial	1%
R1	Compact residential	6%
R2	Compact residential	3%
R3	Compact residential	3%
Total percent urban		20%

As the table indicates, approximately 80 percent of the land use within three kilometers of the site was classified as rural. Rural dispersion coefficients were thus used in the modeling analysis.

Building Downwash

USEPA's Building Profile Input Program (BPIP) was used to compute Good Engineering Practice (GEP) stack heights for each emission source (see "GEP Stack Height and Plume Downwash" following). The program then computed direction-specific building dimensions (height and projected width) for each non-GEP stack to be modeled. These dimensions were used by the ISC3 model to simulate downwash effects for each point source exhausting at heights less than GEP stack height. All proposed stacks at the facility were characterized as non-GEP stacks. Impacts in building cavity regions due to downwash effects on these non-GEP stacks were addressed with the SCREEN3 model as described in the "SCREEN3 Cavity Analysis" following.

Receptors

Receptors were modeled along the facility fence line and at off-site locations up to 20 kilometers beyond the facility. The receptors along the facility fence line are placed at 100-meter intervals. Two Cartesian grids centered on the facility represented the off-site receptors. The first grid extends to a distance of 1.0 kilometer from the grid origin to the north, east, south, and west, with a receptor spacing of 100 meters. The second grid extends to a distance of 14 kilometers from the grid of origin to the north, east, south, and west, with a receptor spacing of 500 meters. Receptor elevations along the fence line and at the grid locations were obtained from the 7.5-minute USGS topographic maps and 7.5-minute USGS Digital Elevation Models (DEM) for the area. All maximum impacts either occurred at a fence line receptor or a receptor located within the 100-meter spaced grid. Maximum impacts were thus resolved within 100-meter grid spacing per AQD guidance.

Meteorology

Meteorological data representative of the proposed site is required as input to the ISCST3 dispersion model to estimate ambient impacts. In lieu of an on-site data set, dispersion modeling with five years of meteorological data is required. The surface data collected at Oklahoma City [WBAN #13967] for the calendar years 1986-88, 1990-91; the upper air data collected at Oklahoma City [WBAN #13967] for the calendar years 1986-88; and the upper air data collected at Norman [WBAN #03948] for the calendar years 1990-91 are used to model sources located in Canadian County, OK, in accordance with ODEQ guidance. The Oklahoma City station is located approximately 10 miles southeast of the proposed facility location. The Norman station is located approximately 25 miles southeast of the proposed facility location. These data were processed using PCRAMMET into an ISC3-ready format and include wind speed and direction, stability, temperature, and mixing heights. The year 1989 was not used because a monitor was moved from Oklahoma City to Norman, causing a three-week gap in the data.

As required by GAQM, a worst-case operating scenario representative of normal operating conditions was determined to assess short-term SO_2, CO, and PM_{10} impacts using the ISCST3 model. As described earlier, the turbines are expected to operate between approximately 60 and 100 percent load during normal operation. Because short-term SO_2, CO, and PM_{10} emissions are not varied with load, ambient impacts were assessed for each turbine at 50, 75 and 100 percent load using a normalized emission rate of 1 g/s with load-specific source parameters. These impacts were assessed at an array of receptors extending to 3,000 meters from the facility. The elevation at each receptor was assumed to be the greatest elevation at that distance in any direction from the facility. The building dimensions used to simulate downwash effects on the stacks were the dimensions of the turbine building. This structure was determined to result in maximized building downwash effects for the turbine stacks by the BPIP software described previously.

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.

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

In October 1993, USEPA released the Building Profile Input Program (BPIP) to determine wind direction-dependent building dimensions for input to the ISC3 model. The BPIP program builds a mathematical representation of each building to determine projected building dimensions and its potential zone of influence. These calculations are performed for 36 different wind directions (at 10 degree intervals). If the BPIP program determines that a source is under the influence of several potential building wakes, the structure or combination of structures which has the greatest influence (h_b + 1.5 l_b) is selected for input to the ISCST3 model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-case building dimensions for that direction yield a wake region height less than the source's physical stack height, building parameters are set equal to zero for that wind direction. For this case, wake effect algorithms are not exercised when the model is run. The building wake criteria influence zone is 5 l_b downwind, 2 l_b upwind, and 0.5 l_b crosswind. These criteria are based on recommendations by USEPA.

Due to the relatively high, but less than GEP, stack heights, and the relatively small size of the dominant structures, the building cavity effects that were considered in the modeling analysis were minimal. For this analysis, the first step was to determine the building cavity height based on the formula:

$$h_c = H + 0.5L_b$$

where:

h_c = 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.

If the stack height was greater than or equal to the cavity height, the cavity effect would not affect the downwind maximum impacts. However, if a cavity effect was possible, the length of the cavity was compared to the distance to the nearest receptor.

Due to the size of the property, the location of the sources on the property, the height of the stacks, and the distance of the sources from the fence line, only cavity effects were encountered at the administration building. However, this cavity does not entrain any emissions; therefore, the concentrations at all receptors were estimated using the normal procedures in the ISCST3 model.

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. The proposed CTs can operate at various loads. The emission rates used for the analysis were the maximum estimated emission rates for each pollutant (except NO_x) at maximum load and minimum exhaust temperature. NO_x was modeled using a monthly average lbs/hr rate to show compliance with an annual averaging time.

STACK PARAMETERS

Source	Stack Height ft	Stack Diameter ft	Stack Velocity ft/sec	Stack Temperature °F
Stack 1	105	9	64.5	226
Stack 2	105	9	64.5	226
Stack 3	105	9	64.5	226
Stack 4	105	9	64.5	226
Auxiliary Boiler	55	20	30	350
Cooling Tower	57	48.75	25	77

EMISSION RATES PER STACK

Source	NO_X lbs/hr	CO lbs/hr	PM_{10} lbs/hr	SO_2 lbs/hr
Stack 1	55.8	69.2	6.1	3.6
Stack 2	55.8	69.2	6.1	3.6
Stack 3	55.8	69.2	6.1	3.6
Stack 4	55.8	69.2	6.1	3.6
Auxiliary Boiler	3.04	7.9	0.72	0.01
Cooling Tower	--	--	0.59	--

Modeling Results

The maximum predicted impacts for all required pollutants are summarized in the table below. With the exception of the NO_2 (annual average) and PM_{10} (24-hour and annual average) impacts, all off-site ambient impacts associated with operations of the proposed facility are below the respective SAIL. The facility is thus compliant with all corresponding NAAQS and Class II PSD increments for CO (all averaging times).

For the NO_2 (annual average) and PM_{10} (24-hour and annual average) impacts, the corresponding PSD Class II increment, background concentration, and NAAQS are also presented. As shown, the predicted impacts are less than the corresponding available PSD Class II increment, and the sum of the predicted impacts and background concentrations are less than the corresponding NAAQS. Therefore, the proposed facility, in conjunction with existing sources, will not cause or contribute to a violation of any NAAQS or PSD increment standard.

Pollutant	Averaging Time	SAIL (ug/m^3)	Impact (ug/m^3)	Available PSD Class II Increment (ug/m^3)	Background (ug/m^3)	Background + Impact (ug/m^3)	NAAQS (ug/m^3)
NO_2	Annual	1	7.3 (1)	25	26.74	34	100
PM_{10}	24-hour	5	4.7	30	25.6	30.3	150
	Annual	1	1.0	17	25.6	26.6	50
CO	1-hour	2,000	151.8	---	5255	5406.8	40,000
	8-hour	500	64.3	N/A	4684	4748.3	10,000
SO_2	3-hour	25	2.7	512	5.2	7.9	1,300
	24-hour	5	1.4	91	5.2	6.6	365
	Annual	1	0.2	20	5.2	5.4	80
Ozone	1-hour	--	11.37	N/A	213.47	224.84	235

(1) 7.3 is the total maximum impact of this facility plus all nearby significant sources.

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 minor source baseline date was triggered for all counties within the radius of impact by an earlier project. Minor increases and decreases at existing major facilities may impact the increment consumption prior to the minor source baseline date. However, all existing major sources were eliminated from review through use of the "20D Rule." Since all of the sources proposed for the facility are new sources, the amount of increment consumed will be equal to the modeled impacts of all facility sources at their maximum emission rates. The modeled annual impact is 7.3 $\mu g/m^3$. The Class II increment for NO_2 is 25 $\mu g/m^3$. Therefore, adequate increment is available for the proposed facility and other nearby increment consumers.

COMPARISON OF INCREMENT TO AMBIENT MONITORING LEVELS OF SIGNIFICANCE

Pollutant	2nd Highest Modeled Incremental Impacts, ug/m^3	Monitoring Levels of Significance, ug/m^3	Post-Construction Monitoring Required?
NO_2	7.3	14	no
CO	64.3 (8-hr)	575	no
PM_{10}	4.37 (24-hrs)	10	no
Ozone	98 TPY VOC	100 TPY VOC	no
SO_2	1.43 (24-hrs)	13	no

SECTION VI. ADDITIONAL PSD IMPACTS ANALYSES

Additional impact analyses were conducted to assess the impairment to Class I areas, visibility, soils, and vegetation that would occur as a result of the new facility and any commercial, residential, industrial, and other growth associated with the facility. These analyses are discussed in the following sections.

Class I Area Impacts Analysis

The nearest Class I area is the Wichita Mountains Wildlife Refuge, approximately 111 km southwest from the Mustang facility. The two primary tests of significant impact on a Class I area are visibility and pollutant concentrations; at the discretion of the Federal Land Manager, additional impacts such as nitrate deposition may be requested. Visibility impacts are described in the next subsection.

As part of ISC3 modeling, a receptor was placed at the northeast corner of the Wichita Mountains Wildlife Refuge and pollutant concentrations were modeled. The following table shows Class I area significant impact limits and modeled concentrations. No significant impacts were calculated for the Refuge.

Pollutant	SAIL, ug/m^3	Modeled Impacts, ug/m^3
NO_2	1 (24-hours)	0.033
PM_{10}	1 (24-hours)	0.022
SO_2	1 (24-hours)	0.010

Visibility Analysis

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, due to firing natural gas solely, no local visibility impairment is anticipated.

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) may be requested if the source is within 200 km of a Class I area. The facility is approximately 111 km northeast of the nearest Class I area. The applicant was referred to the Fish and Wildlife Service for further instructions, and provided a copy to that division of the Department of the Interior on June 25, 2001.

A visibility impacts analysis was conducted using the EPA software, VISCREEN. VISCREEN inputs NOx, sulfate, soot, and ozone emissions, calculating contrast parameters. There are two primary contrast parameters. “Delta-E” is a color difference calculated to determine plume perceptibility. A Delta-E value of 2.00 or less indicates acceptable plume perceptibility. The calculated value here was 0.714. The other primary parameter is “contrast,” a light intensity value between plume and background. The acceptable range for “contrast” is –0.05 to 0.05. The calculated value was 0.003. Since this screening procedure indicated no significant impact on visibility at the nearest Class I area, no further visibility analysis was indicated.

Growth Analysis

A growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the facility and to estimate emissions resulting from that associated growth. Associated growth includes residential and commercial/industrial growth resulting from the new facility. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. The number of new permanent jobs created by the project is expected to be approximately 25. To the extent possible, these jobs will be filled from the local labor pool. Accordingly, negligible new growth is anticipated as a result of the new facility.

Ambient Air Quality Analysis

The additional impacts analysis requires that all regulated pollutants be included in an ambient air quality analysis. The preceding sections describe the air quality impact analysis conducted to demonstrate that emissions of NO_x, CO, SO_2, and PM_{10} from the new facility will result in ambient impacts less than the applicable NAAQS and PSD increments.

Soils & Vegetation Analyses

The following discussion will review the project's potential to impact its agricultural surroundings based on the facility's allowable emission rates and resulting ground level concentrations of ozone and NO_X. Ozone and NO_X were selected for review since they have been shown to be capable of causing damage to vegetation at elevated ambient concentrations.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH. Research by Heck and Brandt cautioned against using data for any exposure period greater than 10 to 12 hours. Heck and Brandt defined a "sensitive" plant species as being susceptible to injury by NO_2 from an 8-hour exposure of 1.5 to 5.0 ppm, or a 1-hour exposure to ozone of 0.10 to 0.25 ppm. The NAAQS value for NO_2 (100 ug/m^3) is equivalent to 0.053 ppm, or roughly one-thirtieth of the lowest threshold for plant injury. The NAAQS limit for ozone (0.12 ppm) is approximately equal to the lowest value at which plant injury was observed. At the concentrations modeled, there is negligible potential for injury to native plants or crops.

NO_2 may affect vegetation either by direct contact of NO_2 with the leaf surface or by solution in water drops, becoming nitric acid. Acute and chronic threshold injury levels for NO_2 are much higher than those for SO_2 (USEPA, 1971).

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. No significant adverse impact on soil and vegetation is anticipated due to the proposed power plant.

Non-Criteria Pollutant Analysis

The maximum 24-hour impact of each toxic pollutant was predicted through dispersion modeling for comparison with the maximum acceptable ambient concentration (MAAC) shown below. According to ODEQ guidance, the impact may be predicted with a single year of meteorological data if the resulting concentration is less than 50 percent of the MAAC. The 1991 meteorological data set was used for the toxic air contaminant analysis. All resulting toxics concentrations are less than 50 percent of the MAAC; therefore, no additional modeling was performed.

Pollutant	Category	24-Hour Impacts	
		MAAC, μg/m^3	Impacts, μg/m^3
Ammonia	C	1,742	4.282
Formaldehyde	A	12	0.157
Pentane	C	35,000	0.246
H_2SO_4 *	A	10	0.717

* Proportioned from 24-hour SO_2 impacts and relative emission rates.

SECTION VII. 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. The current project will be a major source subject to Subchapter 8.

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

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

Emission limitations for all the sources are taken from the construction permit application.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day following the malfunction or release. Within ten (10) working days after the immediate notice is given, the owner or operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Part 70/Title V sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.

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

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
Subchapter 19 regulates emissions of PM 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 burner, auxiliary boiler(s), emergency generator, and fire pump are subject to the requirements of this subchapter.

Equipment	**Maximum Heat Input (HHV), (MMBTU/hr), (per unit)**	**Allowable Particulate Emission Rate, (lbs/MMBTU)**	**Potential Particulate Emission Rate, (lbs/MMBTU)**
LM6000 Turbines	450	0.22	0.0117
Duct Burners	185	0.28	0.010
Emergency Diesel Generator	7.3	0.60	0.10
Fire Pump	1.76	0.60	0.31
Auxiliary Boiler	31	0.45	0.0076

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 engines and boilers will remain compliant with this rule by ensuring "complete combustion" or utilizing pipeline-quality natural gas as fuel in the proposed boiler(s). The combined cycle units are not subject to Subchapter 25 since they are subject to an opacity limitation of NSPS Subpart Db.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. No activities are expected that would produce fugitive dust beyond the facility property line.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lbs/MMBTU heat input. Burning only commercial natural gas will provide compliance for the turbines and duct burners with SO_2 emissions of 0.0056 lb/MMBTU. The emergency diesel generator and diesel fire pump will fire diesel fuel and have maximum sulfur compound emissions of 0.05 lbs/MMBTU, which is well below the allowable emission limitation of 0.8 lbs/MMBTU for liquid fuels.
Part 5 also requires opacity and sulfur dioxide monitoring for equipment rated above 250 MMBTU/hr. Equipment burning gaseous fuel is exempt from the opacity monitor requirement, so the turbines do not require such monitors. Equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitor requirement. The maximum permissible amount of sulfur in commercial quality gas is more than an order of magnitude below 0.1 weight percent, so the turbines do not require such monitors.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTU/hr to emissions of 0.2 lbs of NO_x per MMBTU, 2-hr maximum. The turbines have been equipped with DLN technology so emissions will be 0.091 lbs/MMBTU for simple cycle operations. For combined cycle operations, emissions will be 0.032 lb/MMBtu. The duct burners will have NOx emissions of 0.08 lb/MMBTU or less. The auxiliary boiler(s), emergency diesel generator and the diesel fire pump are below 50 MMBTU/hr heat input and are, therefore, not subject to this rule.

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

OAC 252:100-37 (Volatile Organic Compounds) [Part 7 Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The vapor pressure of diesel is less than 1.5 psia, therefore, Part 3 does not apply.
Part 5 limits the VOC content of coating used in coating lines or operations. This facility will not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize VOC emissions. Temperature and available air must be sufficient to provide essentially complete combustion. The turbines are designed to provide essentially complete combustion of organic materials.

OAC 252:100-41 (Hazardous and Toxic Air Contaminants) [Applicable - State Only]
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2000, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, CC, DD, EE, GG, HH, II, JJ, KK, LL, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, FFF, 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 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 which exceeds the de minimis level does not cause or contribute to a violation of the maximum acceptable ambient concentration (MAAC). Compliance with the MAAC for ammonia, formaldehyde and pentane was shown in Section VI BACT for formaldehyde and H_2SO_4 emissions was analyzed in Section IV for VOC and SO_2 emissions, respectively.

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 Reduction	not eligible
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Feed & Grain Facility	not in source category
OAC 252:100-39	Nonattainment Areas	not in a subject area
OAC 252:100-47	Landfills	not type of emission unit

SECTION VIII. FEDERAL REGULATIONS

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

NSPS, 40 CFR Part 60 [Subparts Db, Dc and GG Applicable]
Subpart Db (Industrial-Commercial-Institutional Steam Generating Units) affects electric steam generating units with a design capacity greater than 100 MMBTU/hr constructed after June 19, 1984. Combined-cycle gas turbines with such capacity are affected sources only if fuel combustion in the heat recovery unit exceeds the 100 MMBTUH level. The application lists the heat input as 185 $MMBTU/hr_{LHV}$. Emission standards, monitoring requirements, and performance testing are described for PM (opacity), SO_2 and NO_X.

§60.42b provides standards for SO_2 emissions. There is no applicable standard for natural gas fired units.

The §60.44b standard for NO_X is 0.20 lbs/MMBTU. Maximum NO_X anticipated from HRSG emissions is 0.091 lbs/MMBTU. Initial compliance is based on a Method 20 testing as per 40 CFR 60.46b(f). Continued compliance is based on a 3-hour average of NO_x emissions. Continuous monitoring of NO_X is required per §60.48b(b), but installation of CEMS as required for 40 CFR Part 75 (Acid Rain) fulfills this requirement.

Subpart Dc (Small Industrial-Commercial-Institutional Steam Generating Units) affects boilers with heat input capacities between 10 and 100 MMBTUH. The only standard specified for gas-fired units is to keep records showing fuel used.

Subpart GG (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 MMBTU/hr or more. Each LM6000 turbine has a lower heating value firing rate of 406 MMBTU/hr and is subject to this subpart. Standards specified in Subpart GG limit NO_x emissions to 75 ppmvd or less. 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]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, mercury, radionuclides, or vinyl chloride except for trace amounts of benzene. Subpart J, Equipment Leaks of Benzene, concerns only process streams which contain more than 10% benzene by weight. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.

NESHAP, 40 CFR Part 63 [Not Applicable at This Time]
There are three subparts which may affect the proposed project: Subpart YYYY: "Combustion Turbines," scheduled for promulgation by May 2002; Subpart ZZZZ: "Reciprocating Internal Combustion Engines," also scheduled for promulgation by May 2002; and Subpart DDDDD, "Industrial, Commercial and Institutional Boilers and Process Heaters," scheduled for promulgation by May 2002. Air Quality reserves the right to re-open this permit if any of these standards become applicable. Subpart B, "Case-by-Case MACT," is not applicable since the facility will not be a major source of HAPs.

CAM, 40 CFR Part 64 [Applicable For Combined Cycle Operations Only]
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 when the facility operates in simple cycle mode. Dry low NO_x burners and steam injection are considered passive control measures because they prevent the formation of pollutants instead of capturing or destroying them. For combined cycle operations, this rule will apply to the SCR system.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
Until or unless combined cycle operations are initiated, this facility will not process or store more than the threshold quantity of any regulated substance (Section 112r of the Clean Air Act 1990 Amendments). The facility will be required to submit a Risk Management Plan on or before the date when ammonia stored on location exceeds the threshold quantity. 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 IX. COMPLIANCE

Tier Classification And Public Review

This application has been determined to be **Tier III** based on the request for a construction permit for a new PSD major stationary source which emits 100 TPY or more of any pollutant subject to regulation. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant leases the land and has notified the landowner. This site is not within 50 miles of the Oklahoma border.

The applicant published the "Notice of Filing a Tier III Application" in the El Reno *Tribune*, on June 20, 2001. The notice stated that the application was available for public review at the El Reno Municipal Building and the DEQ Office at 707 North Robinson, in Oklahoma City. A draft of this permit was submitted to public review by another published notice in the *El Reno Tribune* on July 26, 2001. The notice stated that the draft permit was available at the El Reno Municipal Building and ODEQ Oklahoma City offices.

No comments were received from the public, but two comments were received from EPA Region VI:

1. The proposed best available control technology (BACT) to control the emissions of nitrogen oxides (NOx) from the four new gas-fired combined cycle turbines is dry low NOx combustion. This technology is proposed to achieve NOx emissions of 25 ppmvd. Recent permitting action by the State (sic) of Texas (Westvaco, Texas, LP PSD-TX-962) regarding similar gas-fired combined cycle turbines specified that selective catalytic reduction (SCR) technology would achieve NOx emission limits of 5 ppmvd. The applicant should give any unique and compelling reason for the use of dry-low (sic) combustors to control NOx emissions from the gas-fired combined cycle turbines instead of SCR technology.

2. The proposed BACT to control the emissions of carbon monoxide (CO) from the four new gas-fired combined cycle turbines is good combustion practices. This technology is proposed to achieve CO emissions of 40 ppmvd. Recent permitting action by the State (sic) of Texas (Westvaco, Texas, LP PSD-TX-962) regarding similar gas-fired combined cycle turbines specified that oxidation catalyst technology would achieve CO emission limits of 22 ppmvd. The applicants should give any unique and compelling reason for the use of good combustion practices to control CO emissions from the gas-fired combined cycle turbines instead of oxidation catalyst technology, or equivalent technology.

AQD Response

Westvaco is located near a non attainment region (Houston, TX). The reasoning for SCR at that location is unknown. However, according to the vendor, the dry low-NOx control of 25 ppmdv represents state-of-the-art control of NOx. SCR is not a cost-effective NOx control for simple-cycle operation. However, the applicant has agreed to limit operations to 3,504 hours per year for each gas turbine operating in simple cycle mode. If/when the applicant initiates combined cycle operations, the facility will install SCR (or equivalent control) and will be authorized to operate up to 8,760 hours in combined cycle mode.

Similarly, the vendor assures us that 40 ppm CO constitutes state-of-the-art controls for CO from these turbines. It would seem this results primarily from smaller combustion zones and thus reduced residence time of exhausts. We believe that the driving force behind the determination to install catalytic oxidation is that the Westvaco facility is close to the Houston-Galveston non-attainment area. There is no such non-attainment issue for the Oklahoma City area. However, NAAQS compliance is not an issue; therefore, the excessive cost of catalytic oxidation constitutes a compelling reason to reject this control technology.

Changes to the permit made subsequent to the end of the public review period result only in a more strict permit with lesser impacts to the environment. An additional public review period is not necessary.

Information on all permit action is available on the DEQ web page: www.deq.state.ok.us.

Fees Paid

Major source construction permit fee of $2,000.

SECTION X. SUMMARY

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

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Mustang Power LLC.
Mustang Power Plant **Permit Number 2001-132-C (PSD)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on May 10, 2001, and additional information supplied on June 19, 2001. The Evaluation Memorandum dated February 13, 2002, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

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

a. **Each (of four) LM6000 Combustion Turbines (12-month rolling total):**

Pollutant	**Simple-Cycle Operation**		
	lbs/hr	**TPY [(1)]**	**ppmd @15% O_2**
NO_x	41.00	71.83	25
SO_2	2.54	4.45	
PM_{10}	3.97	6.96	
VOC	1.20	2.10	
CO	59.00	103.37	40 [(2)]
H_2SO_4	0.97	1.70	

[1] 12-month rolling total.
[2] The CO limitation is a 12-month rolling average.

b. **Each (of four) LM6000 Combustion Turbines and 185 MMBTUH Duct Burners (12-month rolling total):**

Pollutant	**Combined-Cycle Operation**		
	lbs/hr	**TPY [(1)]**	**ppmd @15% O_2 [(2)]**
NO_x	11.16	48.49	5
SO_2	3.58	15.55	
PM_{10}	6.06	26.27	
VOC	5.73	24.51	
CO	69.18	301.69	40
H_2SO_4	1.21	5.27	
Ammonia	8.25	35.92	10

[1] Each turbine/duct burner combined, 12-month rolling total.
[2] The ppm limitation is a 12-month rolling average.

c. **Other Units:**

Pollutant	Auxiliary Boiler(s)		Emergency Generator		Cooling Towers(2)	
	lbs/hr	TPY(1)	lbs/hr	TPY(1)	lbs/hr	TPY(1)
NO_X	3.04	9.88	23.36	9.34	--	--
CO	2.55	8.30	6.21	2.48	--	--
VOC	0.17	0.54	0.66	0.26	--	--
SO_2	0.17	0.56	0.35	0.15	--	--
PM_{10}	0.23	0.75	0.73	0.29	4.12	18.08

(1) 12-month rolling average.
(2) Combined from all vents.

1. The diesel fire pump and the two four-cell cooling towers emissions are considered to be insignificant (less than 5 TPY for any one pollutant).
2. The emergency generator shall be fueled with diesel containing a maximum sulfur content of 0.05% by weight.
3. The auxiliary boiler(s) are subject to NSPS Subpart Dc. Records shall be kept showing fuel(s) used. [40 CFR 60.47c(g)]

2. Compliance with the authorized emission limits of Specific Condition No. 1 for the combustion turbine and duct burners shall be demonstrated by fuel usage monitoring, initial performance testing, and/or continuous emissions monitoring designed to satisfy the requirements of federal NSPS and Acid Rain programs, and to confirm the manufacturer-guaranteed emission factors. Performance testing is discussed in greater detail in Specific Condition No. 15. [OAC 252:100-8-6(a)(1)]

3. A serial number or another acceptable form of permanent (non-removable) identification shall be on each turbine. [OAC 252:100-8-6(a)(1)]

4. Upon issuance of an operating permit, the permittee shall be authorized to operate the turbines up to 3,504 hours per year (12-month rolling period) when operating in simple cycle mode. . Each duct burner shall be limited to operating 8,500 hours per rolling 12-month period. If/when the permittee begins combined cycle operations, the gas turbines will be authorized to operate 8,760 hours per year. The auxiliary boiler(s) shall be limited to 6,500 hours per year. The emergency generator is limited to 800 hours of operation per rolling 12-month period. The fire pump is considered an insignificant activity and shall be limited to 500 hours of operation per rolling 12-month period to preserve insignificant status. [OAC 252:100-8-6(a)]

5. 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 252:100-8-5(d)]

   a. The LM6000 combustion turbines shall have dry low-NO_X combustors for simple cycle operations.

b. The LM6000 combustion turbines shall have SCR (or equivalent control) for combined cycle operations.
c. Emissions from the emergency generator and fire-water pump engines shall be controlled by properly operating per manufacturer's specifications, specified fuel types and limits as listed in Specific Condition #1 and #4.
d. The auxiliary boiler(s) shall have low-NOx burners achieving 0.10 lb/MMBTU NOx or less.

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

7. The turbines are subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart GG, and shall comply with all applicable requirements.

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

8. The duct burners associated with the LM6000 combustion turbines are subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart Db, and shall comply with all applicable requirements.

a. 60.44b(a): Standard for nitrogen oxides
b. 60.46b: Compliance and performance test methods and procedures for NO_x
c. 60.49b: Reporting and recordkeeping requirements. Pursuant to 40 CFR 60.48b(h), a continuous monitoring system for NO_x is not required for the duct burners. Therefore, 60.49b(g) and (h) do not apply because the provisions are only applicable to affected facilities required to install a continuous monitoring system.

9. The auxiliary boiler(s) are subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart Dc, and shall comply with all applicable requirements.

a. 60.48c(g): Reporting and Recordkeeping Requirements

10. The permittee may use the following fuel monitoring procedures as alternative monitoring to the provisions of 40 CFR 60.334(b) and 40 CFR 60.335(a) and (d):

a. Monitoring of fuel nitrogen content shall not be required while pipeline quality natural gas is the only fuel fired in the gas turbines.
b. The documentation requirements for pipeline quality natural gas in § 2.3.1.4 and the procedures for sulfur content determination in § 2.3.3.1 of Appendix D to 40 CFR Part 75 shall be used to monitor the fuel sulfur content.

c. The permittee shall notify the Oklahoma Air Quality Division if the sulfur fuel monitoring conducted per item b. above indicates noncompliance with the standard in 40 CFR 60.333(b).

11. The permittee may use NO_x CEMS, which is required by 40 CFR 75.12, as an alternative to the requirements, under 40 CFR 60.334(a) and 40 CFR 60.335(c)(2), to install, monitor and record the turbines' fuel consumption. This alternative monitoring is subject to the following conditions.

a. The NO_x CEMS must be capable of calculating 1-hour and 3-hour average NO_x emissions concentrations corrected to 15% oxygen.
b. The permittee shall submit reports of excess emissions as required in 40 CFR 60.7(c) and summary reports as required in 40 CFR 60.7(d). Excess emissions are defined as all periods when the 3-hour average concentration is greater than the standard for NO_x in 40 CFR 60.332(a)(1).

12. The permittee shall comply with all acid rain control permitting requirements, NO_x and SO_2 monitoring requirements, and SO_2 emission allowance requirements as applicable in 40 CFR Part 72 through Part 75.

13. The permittee shall install, calibrate, operate, and maintain a CO continuous emissions monitoring system on each combustion turbine/duct burner. [OAC 252:100-8-6(a)]

14. The NO_X concentration limits and the CO hourly limits 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 two hours per occurrence. When monitoring shows concentrations in excess of the 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. Within 60 days of achieving maximum power output from each turbine generator set, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with Subpart GG for the combustion turbines, Subpart Da for the duct burners, and Subpart Dc for the auxiliary boiler. In the event the facility operates in simple cycle mode prior to constructing combined cycle capability, the facility will test the gas turbines for the simple cycle operations within the time specified above. Once duct burners are added for combined cycle operations, the facility will test the turbine/duct burners within 60 days of achieving maximum power output, not to exceed 180 days from combined cycle initiation.

[OAC 252:100-8-6(a), 40 CFR Part 60.8]

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

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

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

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

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

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

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4:	Determination of Moisture in Stack Gases.
Method 5:	Determination of Particulate Emissions from stationary sources.
Method 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

16. 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 252:100-8-6(a)]

a. CEMS data required by the Acid Rain program.
b. Operating hours for the fire pump engine and emergency generator (12-month rolling total).
c. Total hours of operation for each combustion turbine and duct burner (monthly and 12-month rolling total).
d. Fuel sulfur documentation required by Specific Condition 9.b.

17. During periods when the CO continuous emission monitoring system is inoperable, the applicant shall use emission factors in conjunction with heat-input rate or load data to estimate emissions. The emission factors for each turbine/duct-burner shall be determined from stack test data and/or historical data from the continuous emission monitoring system. [40 CFR Part 75]

18. During the periods when the NO_x continuous emissions monitoring system is inoperable, the provisions of 40 CFR Part 75 shall be followed to substitute the missing data.

19. The permittee shall apply for a Title V operating permit and an Acid Rain permit within 180 days after operational start-up. [OAC 252:100-8-4(b)(5) and (9)]

PERMIT

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

Date ___________________________ **Permit No. 2001-132-C (PSD)**

Mustang Power LLC, having complied with the requirements of the law, is hereby granted permission to construct an electric power cogeneration plant located in Sec. 36 – T 12N – R 5W_ near Mustang, Canadian County, Oklahoma,

subject to the following conditions, attached:

[X] Standard Conditions Dated October 17, 2001

[X] Specific Conditions

____Executive Director

DEQ Form 885
Revised 7/93

Mustang Power LLC
Attn: Mr. David Graeber
10440 N. Central Expressway, Suite 1400
Dallas, TX 75231

SUBJECT: Permit Application No. 2001-132-C (PSD)
Mustang Cogeneration Plant
Sec. 36 – T 12N – R5W
Mustang, Canadian County, Oklahoma

Dear Mr. Graeber:

Enclosed is the permit authorizing construction of the referenced operation. Please note that this permit is issued subject to certain standards and specific conditions, which are attached.

Thank you for your cooperation in this matter. If we may be of further service, please contact our office at (405)702-4198.

Sincerely,

David S. Schutz, P.E.
AIR QUALITY DIVISION
Enclosures