OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **July 15, 2013**

TO: Phillip Fielder, P.E., Permits and Engineering Group Manager

THROUGH: Phil Martin, P.E., Existing Source Permits Section Manager

THROUGH: Peer Review, David Pollard, ROAT

FROM: Herb Neumann, Regional Office at Tulsa (ROAT)

SUBJECT: Permit No. **2003-410-C (M-4) PSD**
American Electric Power
Public Service Company of Oklahoma
Northeastern Power Station (SIC 4911)
Section 4, T22N, R15E, Rogers County, OK
Driving: From US 169 and OK 88 approximately one mile south of Oologah, east on OK 88 roughly 200 yards to driveway at 36.43783° N, 95.70537° W.

I. INTRODUCTION

Northeastern Power Station generates electricity using both combustion and steam turbines. Applicant has added low-NO_X concentric firing systems (LNCFS, which is a trademark for Alstom's system) consisting of low-NO_X burners (LNB) and separated overfire air (SOFA) to coal-fired Units 3 and 4 in advance of EPA's CSAPR requirements, under operating permit modification 2003-410-TVR (M-3), issued March 8, 2012. That permit was a minor modification. Applicant now requests authority to tune the SOFA units to further decrease NO_X emissions. This is expected to increase CO emissions.

Installation of the LNCFS™ involved minor changes to the burner configuration, burner tips, and the wind box to control combustion temperature and to minimize potential slagging. Miscellaneous structural, piping and electrical changes were also necessary to install the system. This application requests further tuning of the burners to reduce the stoichiometry within the firing zone. The use of Overfire Air (OFA) is one of the most common and accepted methods for reducing NO_X emissions from tangentially-fired boilers. OFA stages the combustion process by injecting a portion of the secondary air above the main firing zone to reduce the initial amount of oxygen available for the fuel. This reduction in O_2 in the main furnace zone creates conditions where the chemical kinetics promote the formation of molecular nitrogen (N_2) instead of NO_X. Heat input, exhaust temperature, exhaust velocity, etc. do not change appreciably as part of the LNCFS™. Because LNCFS™ involves only the aforementioned mechanical changes to the boilers, air emissions, excluding NO_X and CO, are not generally affected. Tuning, such as changing damper curves, windbox/furnace differentials, O_2 curves, etc. to minimize NO_X are required after installation of SOFA. Increases in CO will be minimized with the manual yaw adjustment of the SOFA air nozzle tips. Tuning emission increases were not identified in the application for initial installation of SOFA.

Applicant also desires to install low-NO_X burners and overfire air (LNB/OFA) on Unit 2, which is a natural gas-fired unit. This is expected to decrease NO_X and increase CO emissions, although the manufacturer states that the system will not increase CO emissions, and may decrease them. A staged combustion system is one of the most effective techniques for reducing NO_X emissions from a combustion process, such as that found in boilers. Such systems have two major components, LNB and OFA ports. LNB are specifically designed to operate at a deficiency of the air normally required to complete the combustion process (sub-stoichiometric). OFA ports located higher in the furnace provide the balance of the combustion air to complete combustion prior to flue gas exiting the lower furnace. Approximately 80% of the necessary combustion air is provided to the burners and the remaining 20% is provided via the OFA ports. When a fuel rich condition is created in the burner zone, NO_X that is formed near the burner exit during flame formation is destroyed by hydrocarbon radicals that are produced farther downstream of the burner exit. The balance of the combustion air is reintroduced by the OFA ports gradually mixes with the products of combustion from the burner zone in order to complete the combustion process. This is done in such a manner as to minimize peak flame temperatures and avoid thermal NOx formation. Gas elements of the B&W XCL-S burner proposed for this project are centrally located in the burner in an arrangement that carefully limits air/fuel interaction in the root of the flame. Fuel elements are housed in a single central flame stabilizer that separates the fuel elements from the combustion air. Optimum overfire air mixing characteristics can be achieved with the Dual Zone NO_X Port through its independent control of total air flow, air swirl, and air split between the penetration inner zone and variable swirl outer zone.

The proposed changes are expected to satisfy the Units 3 and 4 BART requirements for NO_X, as described in 96-288-TV (M-3), currently under review. They will have no significant effect on BART SO_2 requirements. Applicant has determined that the effect of the specific changes proposed here will reach the threshold for PSD significance, so this application is treated as a Tier II significant modification.

II. FACILITY DESCRIPTION

Unit 1 has been "repowered." The boiler powering the steam turbine was replaced by two 160 MWe combined cycle gas turbines with heat recovery steam generators (HRSGs). Steam generated by the heat from the turbines and HRSGs re-powers the Unit 1 steam turbine, which was not removed when the original boiler was removed. The gas turbines (combustion turbines or CTs) are not capable of simple cycle operations. The design of the repower system is such that there is no bypass capability; thus, every startup of the CTs requires that all equipment in the combined cycle operation be operated.

The boiler providing steam to Unit 2 is primarily gas-fueled, with #2 fuel oil as a secondary fuel. The boilers providing steam for Units 3 and 4 are primarily coal-fired, with natural gas, #2 fuel oil, and co-firing of coal and natural gas as secondary fuels. Two additional boilers serve as auxiliary gas-fired steam generators, one serving Units 1 & 2 (Auxboiler 1/2), and another serving Units 3 & 4 (Auxboiler 3/4). Although applicant uses the designation “Unit” to refer to the entire generating unit, including the boiler and all appurtenances, the turbine/generator, connecting piping and all controls, this Memorandum will frequently mean only the boiler and appurtenances when using the term. The meaning of the term must be interpreted in context.

This permit includes fly ash handling equipment owned and operated by Boral, thus avoiding a separate Title V permit for that company. Fly ash generated by coal combustion at Northeastern Units 3 & 4 is captured by electrostatic precipitators and initially stored in a fly ash silo. There are two options for removal of the fly ash from the silo. Either option may be required to handle 100% of the fly ash generated, depending on the marketability of the fly ash for sale.

The first option is to unload the fly ash into trucks via chutes at the bottom of the silo for transport offsite for sale. The trucks are fully enclosed and equipped with “portholes” on top for receiving the fly ash and have a capacity of approximately 25 tons. After loading, the trucks move to an adjacent wash station where they are manually washed and then travel approximately one mile over paved road to exit the plant site.

The second option is to transport the fly ash to the landfill. The fly ash is taken from the bottom of the silo through an enclosed conveyor to a Stationary Ash Conditioning System Machine (STACS). Water added in the STACS conditions the fly ash to minimize fugitive dust emissions making the fly ash more manageable. The process from the fly ash silo to the discharge from the STACS is a completely closed system. The conditioned fly ash discharges from the STACS through a fully skirted chute onto a covered conveyor used to load open-topped trucks to transport the fly ash to the landfill. The trucks have a capacity of approximately 15 tons. The trucks travel approximately one mile over unpaved road to the landfill. The typical rate for the STACS process is 100 tons/hr with an estimated maximum rate of up to 150 tons/hr.

After fly ash has been taken to the landfill, it may be reclaimed and sold. The fly ash is loaded into open-topped 15-ton capacity trucks with a front end loader, covered and then transported one mile over unpaved road to the wash station. After the truck is manually washed, it travels one mile over paved road to exit the plant site. Bottom ash is sluiced into a pond. Some of this material is reclaimed, but most is generally dredged and placed elsewhere for long term disposal.

Two operating scenarios are described below. The use of natural gas as ignition fuel in each of these scenarios has trivial effects on emissions of SO_2 as compared with the effects due to oil or coal. The proposed use of petroleum coke (pet coke) is treated in several parts of this permit. Units 3 and 4 have always had the ability to burn pet coke as an alternate fuel for coal and it has not been proscribed. It should be assumed as being represented by coal in the following tables. Auxboiler 3/4 operates under a 10% annual capacity factor. As indicated, Units 3 and 4 are primarily coal-fired, with natural gas, #2 fuel oil, and co-firing of coal and natural gas as secondary fuels. The flexibility of using secondary fuels is implied within Scenarios 1 and 2.

	Units 1A and 1B		Unit 2		Units 3/4
Scenario	**Fuel**	**% Sulfur**	**Fuel**	**% Sulfur**	**Fuel**
1	100% NG	NA	50% Oil/50% NG	≤0.4	100% Coal
2	100% NG	NA	100% NG	NA	100% Coal

The duration of actual fuel use in calendar year 2006, the database year provided with the Title V renewal application, is shown in the first data row of the following table. Fuel use duration for the latest year available, 2011, is shown in the last row.

Unit 1A		Unit 1B		Unit 2		Unit 3		Unit 4	
Fuel	**Hours**	**Fuel**	**Hours**	**Fuel**	**Hours**	**Fuel**	**Hours**	**Fuel**	**Hours**
NG	6,087 (100%)	NG	6,085 (100%)	NG	3,642 (100%)	Coal	7,691 (98%)	Coal	7,623 (98%)
						NG	183 (2%)	NG	140 (2%)
NG	7,102 (100%)	NG	7,437 (100%)	NG	3,071 (100%)	Coal	8096 (99.5%)	Coal	7,994 (99.5%)
						NG	39 (0.5%)	NG	40 (0.5%)

Natural gas firing is usually the mode chosen for start-up and flame stabilization for coal-firing at Units 3 & 4, and does not generally represent long-term natural gas use. Natural gas is used in identical fashion for any Unit preparing to burn oil. Although Units 3 & 4 have the capability to burn oil, to be co-fired on coal and gas, or to be co-fired on oil and gas, no operations in any of these modes for commercial generation occurred during 2006. The applicant wishes to preserve the possibility of oil-burning on a short-term emergency basis. Co-firing coal and natural gas, with potential emissions of SO_2 well below those of burning coal alone, is subsumed in the worst-case analysis performed for each listed Scenario. The auxiliary boilers are fueled only with natural gas, so they have no alternate Scenarios.

III. EQUIPMENT

EUG 1 Gas Turbines and Heat Recovery Steam Generators (HRSG)

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
1	1A	GE MS7001FA S/N 297510	160	1684*	Jan. 2000
1	1B	GE MS7001FA S/N 297511	160	1684*	Jan. 2000

Each turbine exhausts to a 99 MMBTUH Nooter-Erikson HRSG (duct burner). Steam generated by turbine hot exhaust, with additional heat from the HRSG, drives the old steam turbine.
* Under certain operating conditions, the heat input of each turbine may be increased to 1,903 MMBTUH.

EUG 2 Grandfathered Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
2	2	Babcock and Wilcox UP-60	495	4754	Mar, 1970

Upon completion of the proposed project, Unit 2 will be controlled by LNB/OFA.

EUG 3 Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
3	3	Combustion Engineering #4974 SCRR	490	4775	Apr, 1974

Upon completion of the proposed project, Unit 3 will be controlled by LNCFS.

EUG 4 Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
4	4	Combustion Engineering #7174 SCRR	490	4775	Apr, 1974

Upon completion of the proposed project, Unit 4 will be controlled by LNCFS.

EUG Aux 1/2 Steam Generator

EU	Point	Make/Model	MW	MMBTUH	Const Date
Aux 1/2	Aux 1/2	Babcock and Wilcox FM 117-97	N/A	220	Mar, 1997

EUG Aux 3/4 Steam Generator

EU	Point	Make/Model	MW	MMBTUH	Const Date
Aux 3/4	Aux 3/4	Combustion Engineering #3M1004	N/A	239	Apr, 1974

EUG 6 Rotary Car Dumper Baghouse

EU	Point	Make/Model	Const Date
6	6	Peabody #03-21	Apr, 1974

EUG 7 Emergency Reclaim Baghouse

EU	Point	Make/Model	Const Date
7	7	Peabody #S1-5	Apr, 1974

EUG 8 Crusher House Baghouse

EU	Point	Make/Model	Const Date
8	8	Peabody #S2-9	Apr, 1974

EUG 9 Unit 3 Coal Silo Dust Collector

EU	Point	Make/Model	Const Date
9	9	Peabody #D2-10	Apr, 1974

EUG 10 Unit 4 Coal Silo Dust Collector

EU	Point	Make/Model	Const Date
10	10	Peabody #D2-7	Apr, 1974

The next three EUGs are established only for identification of the origin of various fugitive emissions. EU ID# and Point # are identical with the EUG#.

EUG 11 Coal Handling Fugitives

EUG 12 Fly Ash Handling Fugitives (Boral (formerly Monex) Permit 95-427-O)

EUG 13 Bottom Ash Handling Fugitives

EUG ChemStore Stored Chemicals

Material	CAS #	Stored Quantity	Use
Hydrazine	302-01-2	< 2 gallons	Closed cooling systems & aux boiler
Ammonia	7664-41-7	600 lb	Control of boiler water pH

EUG Coal Pile
This covers fugitive emissions from wind erosion of the coal pile.

EUG Plantwide Entire Facility
This EUG is established to cover all rules or regulations that apply to the facility as a whole.

Insignificant Sources
Northeastern Station identifies various pieces of equipment as fitting the insignificant definition. These include two oil-fired emergency generators, ten hydrocarbon storage tanks, a gasoline pump and storage tank, and a fly ash basin.

STACK PARAMETERS

EUG	Point	Height (Ft)	Dimensions	Flow (ACFM)	Temperature (°F)
1	1A	150	18.83′ diameter	1,080,000	200
1	1B	150	18.83′ diameter	1,080,000	200
2	2	183	18.0′ diameter	815,626	249
3/4*	3/4*	600	27.0′ diameter	3,112,410	250
Aux 1/2	Aux 1/2	168.5	4.5′ diameter	54,287	555
Aux 3/4	Aux 3/4	40	8′ diameter	88,500	669
6	6	N/A	76″ × 48″	153,680	Ambient
7	7	N/A	15.5″ × 14″	4,500	Ambient
8	8	N/A	32″ × 29″	20,600	Ambient
9	9	N/A	42″ × 47″	47,950	Ambient
10	10	N/A	39″ × 43″	35,000	Ambient

*Units 3 and 4 share a common stack. Each Unit contributes 1,556,205 acfm.

IV. EMISSIONS

Emission factors for EUG 2 through EUG 6 in the memorandum for 2003-410-TVR (M-2) were based on AP-42 (1/95) as a primary reference, with modifications and updates since January 1995 as identified below. Combustion factors were found in Sections 1.2, 1.3, and 1.4, and coal handling TSP and PM_{10} factors are found in Section 13.2. NO_X factors for all units relied on stack tests in addition to AP-42 factors, the TSP factor for the combined stack at Units 3 & 4 was based on stack testing, and the SO_2 factor for Units 3 & 4 was based on engineering calculations in addition to AP-42 factors. There are electrostatic precipitators for Units 3 & 4 that reduce gas particulate emissions dramatically. The efficiency of the ESP is estimated at 99.6%, but this number does not appear in the tables below, because the stack test result yields a post-control emission factor. Similarly, the NO_X reduction efficiency of staged combustion and modified burners was listed by applicant as 80%, but the stack test result yielded a post-control emission factor.

The LNB/OFA project at Unit 2 is expected to reduce NO_X from the current 0.386 lb/MMBTU to 0.27 lb/MMBTU and to increase CO from the current 0.059 lb/MMBTU to 0.074 lb/MMBTU.

Additional tuning of the LNCFS at Units 3 and 4 will lead to changes in the emission factors used for NO_X and for CO. Applicant expects NO_X emissions to decrease from the current 0.386 lb/MMBTU to the BART level of 0.14 lb/MMBTU. Vendor's data suggests that CO emissions will be at 0.325 lb/MMBTU, up from the current AP-42 equivalent Value of 0.0305 lb/MMBTU. The facility will continue to comply with existing limits until the project is completed.

Emissions for point sources are established as follows. Emissions from Units 1A, 1B, 2, 3 & 4 are calculated based on the two Scenarios described in Section I (Facility Description) above. When a Scenario calls for a mix of fuels, the more polluting fuel is taken for the hourly rate, with the annual emissions representing 4,380 hours of each fuel. Unit 2 has the capability of burning 4.63 MMCFH of gas (40,590 MMCFY) or 32,560 gph of oil (2.85×10^8 gpy). Unit 3 has the capability of burning 266 TPH of coal (2.33×10^6 TPY). Unit 4 has the capability of burning 279 TPH of coal (2.45×10^6 TPY). Coal is assumed to have a heating value of 16.4 MMBTU per ton. Auxiliary boilers burn only gas. A discussion in the memorandum for 2003-410-TVR (M-2) explains that the surrogate for Aux 1/2 authorized emissions were changed from 350 hours of operation per year to 280 MMCF of natural gas per year. The grandfathered steam-generating units were originally estimated to have NO_X emissions based on an old AP-42 factor of 550 lbs/MMCF. CEM data show that actual emission rates are in the mid-400 lbs/MMCF range.

The facility is also subject to Acid Rain Renewal Permit No. 2009-470-2ARR, which establishes a NO_X limit of 0.40 lbs/MMBTU, on an annual average basis through December 31, 2014.

Coal handling equipment is considered to operate continuously. Because of the difficulty involved in presenting the myriad emission factors within the emission table, the AP-42 factors used as default values when test data are not available are listed here. Note that AP-42 gas factors assume a heating value of 1,020 BTU/CF. As a final note, Unit 2 has been grandfathered, and Units 3 & 4 have emission limits in terms of lbs/MMBTU, on an annual average basis, established in Acid Rain Renewal Permit No. 2009-470-2ARR. The foregoing discussion of emission factors used in calculations for EUGs 2, 3, 4, Aux 1/2, and Aux 3/4 is summarized in the following table. To summarize some of the discussion above, and to warn about the proper use of these factors for coal-firing, note the following. First, for calculating short-term NO_X emissions, an AP-42 emission factor of 11.48 Lbs/Ton (0.70 lbs/MMBtu) for NOx must be applied. This 0.70 emission factor represents an NSPS three-hour rolling average limit. The 0.40 lb/MMBTU NO_X datum authorized by the Acid Rain permit is an annualized average, and cannot be used for establishing a short-term limit. Similarly, the 0.14 lb/MMBTU datum proposed for this project is a rolling 30-day average only. Second, the construction permit for units 3 and 4 did not set limits for CO emissions, but the current project does. Third, coal is assumed to have a heating value of 16.4 MMBTU/Ton.

Pollutant	Gas	Oil	Coal
	Lbs/MMCF	Lbs/10^3 gallons	Lbs/Ton
TSP	7.6	2	0.22
PM_{10}	7.6	2	0.15
SO_2	0.6	142S[1]	12.56
NO_X	459[2]	20	2.30
CO	84[2]	5	5.33
VOC	5.5	0.76	0.06

1 S = sulfur content in percent
2 Except for Units 2, 3, & 4

Emission factors for turbines 1A and 1B are based on manufacturer's guarantees. To assure conservatively high results, pound per hour figures are taken at -8°F, while TPY data are taken at average ambient. Note that the NO_X and CO values for the turbines are based on ppmv dry at 15% O_2. Emission factors for the duct burners at this facility are assumed to be similar to those guaranteed by the manufacturer at other GE Frame 7 installations. The factor for sulfuric acid fume emissions is found in AP-42 (9/98) Section 1.3.3.2. Although this part of AP-42 deals with liquid fuels, the discussion makes clear that the formation of acid mist is a function of SO_2 availability and is not a function of burner design or fuel. Worst case assumptions for acid mist and for SO_2 formation include an average annual content of 0.25 gr/100 dscf and an hourly high of 5 gr/100 dscf, along with an average formation rate of acid mist at 3% annually and 5% hourly. Gas heating value is taken to be 1,015 BTU/CF. Emissions calculated for EUG 1 turbines and HRSGs are valid for all operating scenarios.

	Emission	Turbine (ea)		Factor	Duct burner (ea)		Totals	
Pollutant	Factor	lbs/hr	TPY	Lb/MMBTU	lbs/hr	TPY	lbs/hr	TPY
NOx	15 ppm	108	418	0.09	8.91	39.0	234	914
SO_2	0.2 ppm	26.8	5.19	<.001	1.41	0.31	56.4	11.0
PM_{10}	0.011 lb/MMBTU	20.9	81.1	0.01	0.99	4.34	43.8	171
VOC	0.1 ppm	0.40	1.49	0.001	0.10	0.43	1.00	3.84
CO	12 ppm	51.7	198	0.09	8.91	39.0	121	474
H_2SO_4	Per SO_2	2.05	0.24	Per SO_2	0.11	0.01	4.21	0.50

Values from the preceding table for the turbine HRSG sets replacing the old Unit 1 boiler replace the values that appeared in the "Unit 1" column for each of the operating scenarios displayed in the original Part 70 permit memorandum.

SCENARIO 1

Pollutant	Units 1A & 1B		Unit 2		Unit 3		Unit 4	
	Lb/hr	TPY	Lb/hr	TPY	Lb/hr	TPY	Lb/hr	TPY
TSP	43.8	171	52.4	230	64.9	284	64.9	284
PM_{10}	43.8	171	52.4	230	64.9	284	64.9	284
SO_2	56.4	11.0	1,849	4,056	3,702	16,215	3,702	16,215
NO_X	234	914	2,139	4,331	3,343	2,928	3,343	2,928
CO	121	474	352	1,150	N/A	6,797	N/A	6,797
VOC	1.00	3.84	26.0	114	17.7	77.5	17.7	77.5

SCENARIO 2

	Units 1A & 1B		Unit 2		Unit 3		Unit 4	
Pollutant	**Lb/hr**	**TPY**	**Lb/hr**	**TPY**	**Lb/hr**	**TPY**	**Lb/hr**	**TPY**
TSP	43.8	171	35.4	155	64.9	284	64.9	284
PM_{10}	43.8	171	35.4	155	64.9	284	64.9	284
SO_2	56.4	11.0	2.80	12.3	3,702	16,215	3,702	16,215
NO_X	234	914	2,139	5,622	3,343	2,928	3,343	2,928
CO	121	474	352	1,541	N/A	6,797	N/A	6,797
VOC	1.00	3.84	25.6	112	17.7	77.5	17.7	77.5

Lbs/hr values for Auxboiler 3/4 are taken from Specific Condition No. 1 of the original Part 70 permit.

EMISSIONS FROM AUXILIARY BOILER 1/2 & 3/4

Pollutant	Emission factor*	213 MCFH	280 MMCFY
		Lb/hr	TPY
TSP = PM_{10}	7.6 lb/MMCF	1.62	1.06
SO_2	0.6 lb/MMCF	0.13	0.08
NO_X	280 lb/MMCF	59.6	39.2
CO	84 lb/MMCF	17.9	11.8
VOC	5.5 lb/MMCF	1.17	0.77

* Based on a gas heating value of 1,032 BTU/CF.

PARTICULATE EMISSIONS FROM COAL HANDLING (EUGs 6-10)

Source	Pollutant	Emission factor, Lb/ton*	Coal handled		Emissions	
			TPH	TPY × 10^3	Lb/hr	TPY
Car Dumper	TSP	6.551×10^{-6}	2,835	4,621	1.86×10^{-2}	1.51×10^{-2}
	PM_{10}	3.098×10^{-6}	2,835	4,621	8.78×10^{-3}	7.16×10^{-3}
Emergency Reclaim	TSP	2.184×10^{-6}	752	233	1.64×10^{-3}	2.54×10^{-4}
	PM_{10}	1.033×10^{-6}	752	233	7.77×10^{-4}	1.20×10^{-4}
Crusher	TSP	2.184×10^{-6}	545	4,776	1.19×10^{-3}	5.22×10^{-3}
	PM_{10}	1.033×10^{-6}	545	4,776	5.63×10^{-4}	2.47×10^{-3}
Unit 3 Silo	TSP	2.184×10^{-6}	301	2,330	6.57×10^{-4}	2.54×10^{-3}
	PM_{10}	1.033×10^{-6}	301	2,330	3.11×10^{-4}	1.20×10^{-3}
Unit 4 Silo	TSP	2.184×10^{-6}	398	2,446	8.69×10^{-4}	2.67×10^{-3}
	PM_{10}	1.033×10^{-6}	398	2,446	4.11×10^{-3}	1.26×10^{-3}

*All emission factors are calculated utilizing Equation 1 from AP-42 (1/95) Section 13.2.4 using a conservatively high average wind speed value of 9 mph, and then applying the 99.9% efficiency of the baghouse filter. Although this equation may not be entirely appropriate for crusher emissions, it yields values within 8% of those suggested by the analysis in Section 11.19.2 of AP-42, an insignificant difference given the net emission level.

PARTICULATE EMISSIONS FROM MATERIAL HANDLING (EUGs 11-13)

There are 30 acres of “inactive” coal pile and 10 acres of “active” coal pile, per the “frequency of disturbance” discussion in AP-42 (1/95) Section 13.2.5. Since these fugitive emissions may be considered to be continuous, hourly figures are calculated by dividing annual estimates by 8,760 hours. All data are taken from the 1997 Turnaround Document.

EUG	Description	TSP		PM_{10}	
		Lb/hr	TPY	Lb/hr	TPY
11	Coal stockpiles	2.60	11.4	1.25	5.46
12	Flyash handling/silo	1.88	8.22	0.95	4.17
13	Bottom ash handling	0.31	1.37	0.16	0.70

Emissions of particulate (PM_{10}) previously covered under Boral Permit No. 95-427-O are now included in this Title V permit. Calculations from the memorandum associated with that permit are unacceptable, so new assumptions and calculations are performed here. Fly ash collection and transportation from the ESPs is enclosed within the STACS (Stationary Ash Conditioning System) machine until the material is loaded into trucks. The following calculations distinguish among the flyash that is sold off-site, landfilled on-site, or landfilled initially and later sold off-site. No readily available emission factors are found for this loading, so it is treated like the drop operation described in Section 13.2.4 of AP-42 (11/06), using Equation 1 from the section. Thus,

$$E = \{k(0.0032)(U/5)1.3\} \div (M/2)1.4, \text{ where}$$

K = 0.35 (dimensionless, for PM10),
U = 10 mph (wind velocity),
M = 0.25% (moisture content), yielding
E = emission factor (0.051 lbs/ton).

Note that despite the fact that STACS moistens the material, moisture content is taken at the lowest value offered in the tables associated with the equation, maximizing the emission factor. Similarly, although the operation is protected from the wind, a relatively high wind speed is selected, also tending to maximize the emission factor. Using the emission factor generated by this equation with annual throughput of 207,995 tons yields emissions of 5.27 TPY.

For ash landfilled on-site, trucks are assumed to travel two miles for each 15-ton load of fly ash, and the road is assumed to be unpaved. Using equation 1a from Section 13.2.2.2 of AP-42 (11/06) to calculate fugitive emissions from unpaved roads yields

$$E = k(s/12)^a(W/3)^b, \text{ where}$$

s = 6.4% (moisture content of road silt, chosen from Table 13.2.2-1),
W = 15 tons per truck load,
k = 1.5, a = 0.9, b = 0.45 (all dimensionless constants from Table 13.2.2-2 for PM_{10}), and
E = 1.758 lbs/VMT (vehicle miles traveled).

Landfilling an annual total of 207,955 tons of fly ash requires 27,727 miles of travel, thus PM_{10} emissions are 24.37 TPY.

For ash shipped off-site for sale, trucks are assumed to travel one mile for each 25-ton load of fly ash, and the road is assumed to be paved. Using Equation (1) from Section 13.2.1.3 of AP-42 (11/06) to calculate fugitive emissions from unpaved roads yields

$$E = k(sL/2)^{0.65}(W/3)^{1.5}\text{-}C\text{, where}$$

k = 0.016 (dimensionless constant from Table 13.2.1-1 for PM10),
sL = 7.4 g/m^2 (road surface silt loading, chosen from Table 13.2.2-4),
W = 25 tons per truck load,
C = 0.00047 lb/VMT (Emission factor from Table 13.2.1-2 for exhaust, brake wear, and tire wear for PM10)
E = 0.896 lbs/VMT (vehicle miles traveled).

Off-site sales of an annual total of 207,955 tons of fly ash requires 8,318.2 miles of travel, thus PM_{10} emissions are 3.73 TPY.

As an additional activity, fly ash that has been landfilled could later be sold off-site. In that case, trucks are assumed to travel one mile on an unpaved road, and one mile on a paved road. Using the aforementioned AP-42 equations, constants, and variables from Sections 13.2.1.3 and 13.2.2.2 to calculate the emission factors for 15-ton trucks, the PM_{10} emission factors are 1.758 lbs/VMT for the unpaved road, and 0.414 lbs/BMT for the paved road. This activity at the facility occurs only infrequently.

Hazardous Air Pollutants (HAP)
Several AP-42 (9/98) tables list speciated emission factors for coal combustion. Table 1.1-12 presents factors for various polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans. The total of all such constituents amounts to less than 0.01 pounds per year for maximum coal consumption. Table 1.1-13 presents factors for polynuclear aromatic hydrocarbons. The total of all such constituents amounts to less than 100 pounds per year for maximum coal consumption. Table 1.1-14 presents factors for various organic compounds. The following table includes only those compounds from the Tables that are HAPs. Table 1.1-16 presents emission factors for trace elements and uses assay and other information provided by the applicant. Combined fuel consumption for Units 3 & 4 is 9.55×10^9 BTU/hr and 8.366×10^{13} BTU/yr or 589 TPH and 5,164,200 TPY. These assumptions assure conservatively high estimates of all calculated emissions shown in the following table. The introduction to AP-42 discusses the validity of all emission factors used in the document. Quality ratings are assigned to all factors, based on validity of the test method(s) used, the number of methods used within a category, the number of facilities tested, and an assessment of variability as to specific sources within each category. An “A” is assigned to a high number of sources of the same nature, with the same or very similar test methods applied throughout. The lowest rating of “E” suggests that the test(s) used may be of questionable validity, the number of sources may be too small, and that the specific sources tested may be widely variable within the category. After the original Part 70 permit was issued, the Electric Power Research Institute (EPRI) performed a study of numerous coal-fired units and developed a handbook of factors using a model that they named PISCES. This model includes numerous site-specific factors and the facility has used it to generate a corrected emission factor of 0.0624 lbs/ton for hydrogen fluoride (HF) emissions from Units 3 and 4. Hydrogen chloride is addressed individually later in this memorandum.

SPECIATED COAL COMBUSTION EMISSIONS

Chemical	Emission factor	Emissions		Factor Quality
		Lbs/hr	TPY	
Acetaldehyde	0.00057 (t)	0.34	1.47	C
Acrolein	0.00029 (t)	0.17	0.75	D
Antimony	0.93 (b)	0.01	0.04	A
Arsenic	14.75 (b)	0.14	0.62	A
Benzene	0.0013 (t)	0.77	3.36	A
Benzyl chloride	0.0007 (t)	0.41	1.81	D
Beryllium	2.59 (b)	0.02	0.11	A
Cadmium	3.62 (b)	0.03	0.15	A
Chromium	28.72 (b)	0.27	1.20	A
Cobalt	11.38 (b)	0.11	0.48	A
Cyanide	0.0025 (t)	1.47	6.45	D
Formaldehyde	0.00024 (t)	0.14	0.62	A
Hydrogen fluoride	0.0624 (t)	36.8	161	*
Isophorone	0.00058 (t)	0.34	1.50	D
Lead	18.89 (b)	0.18	0.79	A
Magnesium	0.011 (t)	6.48	28.4	A
Manganese	76.32 (b)	0.73	3.19	A
Mercury	0.000083 (t)	0.05	0.21	A
Methyl chloride	0.00053 (t)	0.31	1.37	D
Methyl ethyl ketone	0.00039 (t)	0.23	1.01	D
Methylene chloride	0.00029 (t)	0.17	0.75	D
Nickel	25.35 (b)	0.24	1.06	A
Propionaldehyde	0.00038 (t)	0.22	0.98	D
Selenium	0.0013 (t)	0.77	3.36	A

(b) units are pounds per 10^{12} BTU
(t) units are pounds per ton
* from the EPRI study

A similar analysis may be performed for oil combustion. Scenario 1 shows oil consumption at a rate of 1.08×10^{10} BTU/hr and 5.29×10^{13} BTU/yr. Emission factors are found in AP-42 (1/95) Tables 1.3-9 and 1.3-11.

SPECIATED OIL COMBUSTION EMISSIONS

Chemical	Emission factor (Lbs/10^{12} BTU)	Emissions	
		Lbs/hr	TPY
Arsenic	4.2	0.045	0.111
Beryllium	2.5	0.027	0.066
Cadmium	11	0.119	0.291
Chromium	67	0.724	1.772
Formaldehyde	405	4.374	10.71
Lead	8.9	0.096	0.235
Manganese	14	0.151	0.370
Mercury	3.0	0.032	0.080
Nickel	170	1.836	4.497

EPA has performed a study of electric utility steam generation that tabulates emissions of those chemicals listed in Section 112 of the Clean Air Act. No conclusion was reached as to the need for a MACT, but the emission factors are available for use. The study showed 190 TPY of hydrogen chloride and 14 TPY of hydrogen fluoride emissions from a 325 MWe coal unit, and 9.4 TPY of hydrogen chloride from a 160 MWe oil unit. Scaling from these data to the units at Northeastern, and assuming the worst-case fuel use of any scenario, yields the following table. Better data for hydrogen fluoride were subsequently received per the EPRI study cited above, so the table presents only the hydrogen chloride results.

Unit (MWe)	Pollutant	Lbs/hr	TPY
#2 (*)	Hydrogen chloride	6.64	14.5
#3 (490)	Hydrogen chloride	65.4	286
#4 (490)	Hydrogen chloride	65.4	286

* Lb/hr at 100% and TPY at 50% of 495 MWe

The following table shows speciated HAP emissions, with factors taken from AP-42 (5/98 Draft) Tables 3.1-3 and 4 with conservatively high rates of 1.972 MMCFH for each combustion turbine and duct burner set and 30,777 MMCFY total for all turbines and duct burners.

		Emissions		
Pollutant	**Emission factor**	**Lb/hr/set**	**Total lb/hr**	**Total TPY**
1,3-Butadiene	4.4×10^{-4} lb/MMCF	0.001	0.002	0.007
Acetaldehyde	8.0×10^{-2} lb/MMCF	0.158	0.316	1.231
Acrolein	7.9×10^{-3} lb/MMCF	0.016	0.031	0.122
Benzene	1.4×10^{-1} lb/MMCF	0.276	0.552	2.154
Ethylbenzene	2.4×10^{-2} lb/MMCF	0.047	0.095	0.369
Formaldehyde	3.4 lb/MMCF	6.705	13.41	52.32
Naphthalene	1.4×10^{-1} lb/MMCF	0.276	0.552	2.154
NDMA*	2.3×10^{-4} lb/MMCF	<.001	0.001	0.004
NMOR*	2.3×10^{-4} lb/MMCF	<.001	0.001	0.004
PAHs*	1.8×10^{-1} lb/MMCF	0.355	0.710	2.770
Propylene oxide	2.9×10^{-2} lb/MMCF	0.057	0.114	0.446
Toluene	1.3×10^{-1} lb/MMCF	0.256	0.513	2.001
TMA*	1.7×10^{-4} lb/MMCF	<.001	0.001	0.003
Xylene	2.7×10^{-2} lb/MMCF	0.053	0.106	0.416
Arsenic	4.9×10^{-5} lb/MMCF	<.001	<.001	0.001
Cadmium	8.4×10^{-4} lb/MMCF	0.002	0.003	0.013
Chromium VI	1.3×10^{-3} lb/MMCF	0.003	0.005	0.020
Lead	1.6×10^{-2} lb/MMCF	0.032	0.063	0.246
Manganese	1.6×10^{-3} lb/MMCF	0.003	0.006	0.025
Mercury	4.4×10^{-4} lb/MMCF	0.001	0.002	0.007

*NDMA-N-nitrosodimethylamine, NMOR-N-nitrosomorpholine, PAH-polycyclic aromatic hydrocarbon, TMA-trimethylamine

Two AP-42 (7/98) tables list speciated emission factors for natural gas combustion. Table 1.4-3 presents factors for organic compounds and Table 1.4-4 presents factors for metals. The following table includes only those compounds from the Tables that are HAPs. Combined gas consumption is maximized at 18,329 MMBTUH or 158,827,560 MMBTU/yr.

	Emission factor	**Emissions**	
Pollutant	**Lbs/MMCF**	**Lbs/hr**	**TPY**
3-Methylchloranthrene	1.8×10^{-6}	<.01	<.01
7,12-Dimethylbenz(a)anthracene	1.6×10^{-5}	<.01	<.01
Acenaphthene	1.8×10^{-6}	<.01	<.01
Acenaphthylene	1.8×10^{-6}	<.01	<.01
Benzene	2.1×10^{-3}	0.02	0.08
Benzo(a)anthrene	1.8×10^{-6}	<.01	<.01
Benzo(a)pyrene	1.2×10^{-6}	<.01	<.01
Benzo(b)fluoranthrene	1.8×10^{-6}	<.01	<.01
Benzo(g,h,i)perylene	1.2×10^{-6}	<.01	<.01
Chysene	1.8×10^{-6}	<.01	<.01
Dibenzo(a,h)anthracene	1.2×10^{-6}	<.01	<.01
Fluoranthene	3.0×10^{-6}	<.01	<.01
Fluorene	2.8×10^{-6}	<.01	<.01
Formaldehyde	3.4	28.50	121.7
Hexane	1.8	15.09	64.41
Indeno(1,2,3-cd)pyrene	1.8×10^{-6}	<.01	<.01
Naphthalene	6.1×10^{-4}	<.01	0.02
Phenanthrene	1.7×10^{-5}	<.01	<.01
Pyrene	5.0×10^{-6}	<.01	<.01
Toluene	3.4×10^{-3}	0.03	0.12
Arsenic	2.0×10^{-4}	<.01	0.01
Beryllium	1.2×10^{-5}	<.01	<.01
Cadmium	1.1×10^{-3}	0.01	0.04
Chromium VI	1.4×10^{-3}	0.01	0.05
Manganese	3.8×10^{-4}	<.01	0.01
Mercury	2.6×10^{-4}	<.01	0.01
Nickel	2.1×10^{-3}	0.02	0.06
Selenium	2.4×10^{-5}	<.01	<.01

The preceding analysis does not provide an easy method of estimating HAP emissions on a facility-wide basis. The following table makes a series of conservatively high assumptions to provide a reasonable estimate at total emissions. Any pollutant with emission factors for multiple fuels is assumed to be present in the highest concentration in all fuels, and its emissions are calculated on full facility heat input. For instance, there are emission factors for formaldehyde for gas, oil, and coal. Converted to BTU-equivalents, the highest of these is the factor of 3.4 lbs/MMCF used for natural gas. This factor is converted to 3.3×10^{-3} lbs/MMBTU, and applied to the facility heat input capacity of 18,329 MMBTUH and 158,827,560 MMBTU/yr. These capacities are based on the combined ratings of the turbines, HRSGs, boilers at Units 2, 3, and 4, and the two auxiliary boilers, for the hourly rate, and all of the listed items at 8,760 hr/yr, except for the Aux 1/2 boiler, where operating hours are limited by a permit condition. When two factors exist for one fuel, dependent on the device, such as factors for natural gas at a boiler as opposed to gas at a turbine, the higher factor is assumed for all devices. The table identifies those cases in which data are taken from preceding tables by naming the single fuel controlling that choice.

Chemical	Fuel	Emissions	
		Lbs/hr	TPY
1-3 Butadiene	Gas	<.01	<.01
3-Methylchloranthrene	Gas	<.01	<.01
7-12 Dimethylbenz(a)anthracene	Gas	<.01	<.01
Acenaphthene	Gas	<.01	<.01
Acenaphthylene	Gas	<.01	<.01
Acetaldehyde		1.43	6.20
Acrolein		0.33	1.43
Antimony	Coal	0.01	0.04
Arsenic		0.27	1.17
Benzene		2.57	11.1
Benzo(a)anthren	Gas	<.01	<.01
Benzo(a)pyrene	Gas	<.01	<.01
Benzo(b)fluoranthrene	Gas	<.01	<.01
Benzo(g,h,i)perylene	Gas	<.01	<.01
Benzyl chloride	Coal	0.41	1.81
Beryllium		0.05	0.20
Cadmium		0.20	0.87
Chromium		1.23	5.32
Chysene	Gas	<.01	<.01
Cobalt	Coal	0.11	0.48
Cyanide	Coal	1.47	6.45
Dibenzo(a,h)anthracene	Gas	<.01	<.01
Ethylbenzene	Gas	0.10	0.37
Fluoranthene	Gas	<.01	<.01
Fluorine	Gas	<.01	<.01
Formaldehyde		60.5	262
Hydrogen fluoride	Coal	36.8	161
Indeno(1,2,3-cd)pyrene	Gas	<.01	<.01
Isophorone	Coal	0.34	1.50
Lead		0.34	1.51
Magnesium	Coal	6.48	28.4
Manganese		1.40	6.04
Mercury		0.09	0.40
Methyl chloride	Coal	0.31	1.37
Methyl ethyl ketone	Coal	0.23	1.01
Methylene chloride	Coal	0.17	0.75

Chemical	Fuel	Emissions	
		Lbs/hr	TPY
Naphthalene	Gas	0.55	2.15
NDMA	Gas	<.01	<.01
Nickel		3.11	13.5
NMOR	Gas	<.01	<.01
PAHs	Gas	0.71	2.77
Phenanthrene	Gas	<.01	<.01
Propionaldehyde	Coal	0.22	0.98
Propylene oxide	Gas	0.11	0.45
Pyrene	Gas	<.01	<.01
Selenium	Coal	0.77	3.36
TMA	Gas	<.01	<.01
Toluene	Gas	0.51	2.00
Xylene	Gas	0.11	0.42

GHG (Greenhouse gas) emissions are discussed in the pending renewal Part 70 operating permit.

V. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified on Part 1b of the forms in the application and duplicated below were confirmed by the initial operating permit inspection. Records that confirm the insignificance of the activities are available. Appropriate recordkeeping is required for those activities indicated below with an asterisk.

* Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period. Northeastern dispensed approximately 16,980 gallons of gasoline from a 2,000-gallon tank (Tank #11) during 1997, with no more than 1,600 gallons in any one month.

* Emissions from storage tanks constructed with a capacity less than 39,894 gallons that store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. PSO has three oil fuel tanks; one (#1) with capacity of 33,580 gallons, and two (#2 & #4) with 13,860 gallons capacity each. PSO also has five lube oil storage tanks, including #6, #7, #9 & #10 with 13,860 gallons capacity each, and #8 with 9,000 gallons capacity. None of these tanks is subject to NSPS or to State rules due to construction in the early 1970's, and all store liquids with vapor pressure well below the 1.5 psia threshold.

Emissions from condensate tanks with a design capacity of 10,000 gallons or less in ozone attainment areas. PSO has a natural gas condensate tank (#5) with capacity of 8,459 gallons. Rogers County is in an ozone attainment area.

* Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or oil fuel that are either used exclusively for emergency power generation or for peaking power service not exceeding 500 hours/year. PSO has a 3,688-hp oil-fired emergency generator for service at Units 1 & 2, and has a 1,476-hp oil-fired emergency generator for service at Units 3 & 4.

Neither generator is utilized in excess of 500 hours per year. For example, the Units 3 & 4 generator was tested for a total of nine hours during 1997 and the generator at Units 1 & 2 was operated for 12 hours in the same time period.

The facility proposed a number of sources as insignificant because their emissions are below the 5 TPY State *de minimis* and they are not subject to NSPS, NESHAP, or State rules.

a) The fly ash basin.
b) Cold degreasing operations. The facility purchased 766 gallons of solvent during 2006, for an emission total of 2.9 tons, well below significance levels. No credit was taken for recycled solvent.
c) Torch cutting and welding is used only for maintenance purposes, qualifying it as a Trivial activity, for which no recordkeeping is necessary.
d) Welding and soldering is used only for maintenance purposes, qualifying it as a Trivial activity, for which no recordkeeping is necessary.
e) Hazardous waste and hazardous materials drum staging areas.
f) Surface coating operations is performed only for maintenance purposes, qualifying it as a Trivial activity, for which no recordkeeping is necessary.
g) Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets.
h) Hand wiping and spraying of solvents from containers with less than one liter capacity used for spot cleaning and/or degreasing in ozone attainment areas. Rogers County is in an ozone attainment area.
i) The fuel oil tank (#3), built in 1960, is not subject to NSPS, NESHAP, or OAC Rules. Losses were calculated using Tanks3.1, which indicated that to achieve the *de minimis* threshold emissions of 5 TPY, the tank would have to turnover 73 times per year. Since the worst case oil consumption of any scenario requires only 34 turnovers, this source is below the de minimis threshold, and qualifies as insignificant.
j) Spilled petroleum liquids added to the coal pile for combustion in the boilers. No diesel or lube oil was added to the coal pile in 2006.
k) The fly ash material handling activities contracted to Boral or its successors have emissions calculated at well below 5 TPY, as shown in EUG 12 previously.

VI. OKLAHOMA AIR POLLUTION CONTROL RULES

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

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

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

OAC 252:100-5 (Registration, Emission Inventory, and Annual Operating Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. An emission inventory was submitted and fees paid for previous years as required.

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

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

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the current application, from the existing Part 70 operating permit, or developed from the applicable requirement.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

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

OAC 252:100-19 (Particulate Matter) [Applicable]
Section 19-4 regulates emission of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating, per Appendix C. Unit 2 predates the rule, and is considered to be existing equipment. Fuel-burning equipment is defined in OAC 252:100-19 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. Thus, the following equipment items are subject to the requirements of this subchapter.

Emission factors shown in this table reflect the factors associated with the most-polluting fuel that each item is capable of burning. Ash content of pet coke is much less than that of coal, so use of coal data is a conservatively high assumption. Compliance with these limits for Units 3 and 4 was demonstrated by performance testing on May 11 and June 14, 2006. Discussion of these tests is found in the "Testing" portion of Section VIII (Compliance) below.

Equipment	**Maximum Heat Input (MMBTUH)**	**Emissions in Lbs/MMBTU**	
		Appendix C	**Potential**
Units 1A and 1B gas turbines (ea)	1,684	0.171	0.011
Units 1A and 1B HRSGs (ea)	99	0.348	0.008
Unit 2 B&W boiler	4,754	0.125	0.0146 (oil)
Units 3 and 4 C.E. boilers (ea)	4,775	0.125	0.0146 (oil)
Units 1 & 2 auxiliary boiler	220	0.288	0.008
Units 3 & 4 auxiliary boiler	239	0.282	0.008
Units 1 & 2 3,688-hp generator	124	0.330	0.0146 (oil)
Units 3 & 4 1,476-hp generator	50	0.410	0.0146 (oil)

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall opacity exceed 60%. When burning natural gas there is very little possibility of exceeding the opacity standards.
Units 3 & 4 are equipped with opacity monitors, are subject to an opacity limit under NSPS Subpart D, and are exempt from Subchapter 25 opacity requirements per §25-3(a).

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. There is minimal vehicular traffic, and the main plant roads and main parking lots are paved. Haul roads and the coal yard area are not paved. Fugitive dust emissions are minimized by using water wagons on the haul roads, parking area and coal pile. Coal handling and processing areas such as the dumper building, where coal train unloading takes place, use wet spray systems, fabric filters and air handling systems to minimize fugitive dust emissions. In addition, the processing areas used in the transfer and treatment of coal are washed down with water hoses on a regular basis. Confining the active disturbance to a very small area minimizes fugitives from the coal piles. No additional controls are necessary.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 of the subchapter sets "new" equipment standards that limit SO_2 emissions to 0.2 lbs/MMBTU for gas fuel, 0.8 lbs/MMBTU for liquid fuel, and 1.2 lbs/MMBTU for solid fuel. Units 3 & 4 and auxiliary boilers 1/2 and 3/4 have been installed since the effective date, and are new equipment. Units 3 and 4 have SO_2 emissions of 0.0006 lbs/MMBTU from gas combustion, 0.463 lbs/MMBTU from oil combustion, and 0.717 lbs/MMBTU from coal combustion. Both auxiliary boilers have emissions of 0.0006 lbs/MMBTU from gas combustion. Thus, all units are in compliance.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter affects "new" combustion sources that exceed 50 MMBTUH. Limits for various fuels are set at 0.20 lbs/MMBTU for gas, 0.30 lbs/MMBTU for oil, and 0.70 lbs/MMBTU for solid fuel. Units 3 & 4 and the auxiliary boilers have been installed since the effective date, and are new equipment. NO_X emissions from the Unit 3 & 4 stack are 0.08 lbs/MMBTU for gas, 0.13 lbs/MMBTU for oil, and less than 0.7 lbs/MMBTU for coal. Addition of the low-NOX burners is expected to decrease emissions below the already acceptable levels. NO_X emissions from the auxiliary boilers have a manufacturer's suggested value of 0.12 lbs/MMBTU. Thus, all units will remain in compliance.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
This subchapter affects gray iron cupolas, blast furnaces, basic oxygen furnaces, petroleum catalytic cracking units, and petroleum catalytic reforming units. There are no affected sources.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
<u>Part 3</u> requires storage tanks with a capacity of 400 gallons or more to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Fuel oil and lube oil have vapor pressures below the exemption level of 1.5 psia for VOC, per OAC 252:100-37-4(a). The 2,000-gallon gasoline tank has submerged fill.
<u>Part 5</u> limits the organic solvent content of coating or other operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is not an affected operation.
<u>Part 7</u> requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion. Extensive monitoring of stack emissions is performed, and is adequate to assure compliance with the requirements of OAC 252:100-37-36.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data

from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

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

OAC 252:100-11	Alternative Reduction	not requested
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	Municipal Landfills	not in source category

VII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
This facility is a major stationary source, so emissions increases must be evaluated for PSD if they exceed a significance level (100 TPY CO, 40 TPY NO_X, 40 TPY SO_2, 40 TPY VOC, 25 TPY PM, 15 TPY PM_{10}, 10 TPY $PM_{2.5}$, 0.6 TPY lead). The current low-NO_X project is designed to decrease emissions of NO_X, but may cause an increase in emissions of carbon monoxide or carbon dioxide. The project should have no effect on other pollutants. Because this is considered by applicant to be a single project, data for all three units are combined to determine PSD relevance. Baseline years used for calculations concerning all pollutants are 2008 and 2009.

Full PSD review of emissions consists of the following.

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

NAAQS review
Air dispersion modeling was conducted using 2006-2010 meteorological data processed by AERMET (Version 11059) to generate the surface (SCF) and profile (PFL) files for input into AERMOD. The meteorological data consists of 5-minute Oklahoma Mesonet data as on-site data with National Climatic Data Center (NCDC) Integrated Hourly Surface (ISH) data, and Forecast System Laboratories (FSL) upper air rawinsonde observation (RAOB) data. The Oklahoma Mesonet data was provided to the AQD courtesy of the Oklahoma Mesonet, a

cooperative venture between Oklahoma State University (OSU) and the University of Oklahoma (OU) and supported by the taxpayers of Oklahoma. For this specific modeling analysis, Oklahoma Mesonet data from Claremore (CLRM-122) Mesonet site was combined with ISH data from the Claremore (KGCM-53940) National Weather Service (NWS) station and FSL data from the Norman (OUN-3984) station. As discussed in the following BACT analysis for Units 2, 3, & 4, CO PTE for each unit may be calculated based on proposed post-project emission factors, yielding 351.8 lb/hr for Unit 2 and 1,559 lb/hr for each of Units 3 and 4. The maximum CO impacts from combined Units 2, 3 & 4 are 1-hour: 399 $\mu g/m^3$ and 8-hour: 67 $\mu g/m^3$. These values are well below the NAAQS primary standards of 1-hour: 40 mg/m^3 (40,000 $\mu g/m^3$) and 8-hour: 10 mg/m^3 (10,000 $\mu g/m^3$). There are no secondary standards for CO. Thus, an air quality impact analysis is not required.

Unit 2

Emissions of NO_X are monitored by CEMS, so using actual measured emissions in combination with measured heat inputs for these years allows calculation of an emission factor in terms of pounds per million BTU (lb/MMBTU) for this pollutant. All other criteria pollutants use values from Tables 1.4-1 and -2 of AP-42 (7/98). Factors for GHGs are found in Tables C-1 and C-2 of 40 CFR 98, Subpart C. The GHG factors are stated in kg/MMBTU, and must be converted to lb/MMBTU using factors in Table A-2 of 40 CFR 98 Subpart A, and then multiplied by the factors found in Table A-1 to obtain the CO_2 equivalent (CO_2e) value. The calculations are 0.001 kg/MMBTU × 2.20462 lb/kg × 21 lb CO_2e/lb CH4 = 0.0463 lb/MMBTU for methane and 0.0001 × 2.20462 × 310 = 0.0683 lb/MMBTU for nitrous oxide. Because all emissions are calculated on the basis of heat input, average annual heat input of 10,101,178 MMBTU is shown, rather than individual lines for each year. The following table reflects the data and assumptions of this paragraph, and summarizes the baseline actual calculations.

Pollutant	Factor (Lb/MMBTU)	Emissions (TPY)
CO	0.085	429.3
NO_X	0.386	1,947.2
SO_2	0.000588	3.03
PM_{10}	0.007451	38.9
$PM_{2.5}$	0.007451	38.9
VOC	0.005392	27.8
Lead	4.9×10^{-7}	0.002
CO_2	117	590,192
CH_4 (as CO_2e)	0.0463	233.8
N_2O (as CO_2e)	0.0683	345.1

AEP-PSO uses a program called PROMOD to estimate future generation needs. PROMOD is a fundamental electric market simulation software package that incorporates extensive details in generating unit operating characteristics, transmission grid constraints, unit commitment/operating conditions, and market system operations to predict cost effective dispatch scenarios. Utilities have used various versions of PROMOD extensively for years as the primary tool for projecting generation asset utilization, taking into consideration unit availability, fuel contracts, market demands, plant profitability, weather predictions, transmission capabilities, unit emissions and a range of other factors. The entire generation system and grid dynamics are analyzed and individual unit generation output is predicted as a function of the best economic configuration of the factors involved. The future case emissions for this analysis are based on the best PROMOD run available at the time this project was being evaluated. PROMOD's projections for the next decade show that 2012 is projected to be the highest year, at 9,842,000 MMBTU heat input.

Pollutant	Factor (Lb/MMBTU)	Emissions (TPY)
CO	0.074	364
NO_X	0.27	1,329
SO_2	0.000588	2.89
PM_{10}	0.007451	36.7
$PM_{2.5}$	0.007451	36.7
VOC	0.005392	26.5
Lead	4.9×10^{-7}	0.002
CO_2	117	575,049
CH_4 (as CO_2e)	0.0463	228
N_2O (as CO_2e)	0.0683	336

Use of projected actual emissions allows increases in emissions due to demand increase (PROMOD) that could have been accommodated by the facility during the baseline years to be excluded from the calculations. The demand increase of 9,842,000 minus 10,101,178 is a decrease of 259,178 MMBTU. Using the baseline emission factors, the increase in emissions that may be excluded are shown in the following table.

Pollutant	Factor (Lb/MMBTU)	Emissions (TPY)
CO	0.085	-11.02
NO_X	0.386	-50.02
SO_2	0.000588	0.08
PM_{10}	0.007451	-0.97
$PM_{2.5}$	0.007451	-0.97
VOC	0.005392	-0.70
Lead	4.9×10^{-7}	0.00
CO_2	117	-15,162
CH_4 (as CO_2e)	0.0463	-6.00
N_2O (as CO_2e)	0.0683	-8.85

Finally, projected annual emissions, less baseline actual emissions and less excluded emissions, are compared with the PSD significance threshold in the following table.

Pollutant	Projected	Baseline	Excluded	Net	PSD Threshold	Significant?
CO	364	429.3	-11.02	-54	100	No
NO_X	1,329	1,947.2	-50.02	-568	40	No
SO_2	2.89	3.03	0.08	0	40	No
PM_{10}	36.7	38.9	-0.97	0	15	No
$PM_{2.5}$	36.7	38.9	-0.97	0	10	No
VOC	26.5	27.8	-0.70	0	40	No
Lead	0.002	0.002	0.00	0	0.6	No
GHG	575,613	590,771	-15,177	0	75,000	No

Units 3/4

Emissions of NO_X, SO_2, and CO_2 are monitored by CEMS, so using actual measured emissions in combination with measured heat inputs for these years allows calculation of emission factors in terms of pounds per million BTU (lb/MMBTU) for the three pollutants. Performance tests have yielded factors for VOC and for PM_{10}, and the particle size distribution factors stated in AP-42 allow for the calculation of a $PM_{2.5}$ factor. These factors are also stated in lb/MMBTU. Emission factors for lead, fluorides, and sulfuric acid mist are taken from the Electric Power Research Institute (EPRI) study mentioned previously. The GHG factors are stated in kg/MMBTU, and must be converted to lb/MMBTU using factors in Table A-2 of 40 CFR 98 Subpart A, and then multiplied by the factors found in Table A-1 to obtain the CO_2 equivalent (CO_2e) value. The calculations are 0.011 kg/MMBTU × 2.20462 lb/kg × 21 lb CO_2e/lb CH4 = 0.509 lb/MMBTU for methane and 0.0016 × 2.20462 × 310 = 1.093 lb/MMBTU for nitrous oxide. Finally, applicant has consistently used an AP-42 factor of 0.5 lb of carbon monoxide per ton of coal. Assuming 16.4 MMBTU per ton of coal yields a factor of 0.0305 lb/MMBTU for CO. Because all emissions are calculated on the basis of heat input, average annual heat input of 67,168,869 MMBTU is shown, rather than individual lines for 65,052,479 MMBTU in 2008 and 69,285,258 MMBTU in 2009. The following table reflects the data and assumptions of this paragraph, and summarizes the baseline actual calculations.

Pollutant	Factor (Lb/MMBTU)	Emissions (TPY)
CO	0.0305	1,024
NO_X	0.386	12,964
SO_2	0.59	19,815
PM_{10}	0.0485	1,629
$PM_{2.5}$	0.00835	280
VOC	0.00363	122
Lead	2.441×10^{-6}	0.082
Fluorides	1.7645×10^{-3}	59.3
Sulfuric acid mist	2.275×10^{-4}	7.64
CO_2	206.1	6,921,752
CH_4 (as CO_2e)	0.509	17,099
N_2O (as CO_2e)	1.093	36,714

Because all emission factors are stated in terms of pounds per million BTU (lb/MMBTU), heat input is used as the basis for projected annual calculations. Applicant states that NO_X is expected to decrease to a value of 0.14 lb/MMBTU and CO to increase to a value of 0.325 lb/MMBTU. As indicated in the review of Unit 2, PROMOD was used to determine that 2012 is projected to be the highest year, at 69,356,000 MMBTU heat input. Using the 2012 heat input and the emission factors discussed in the preceding paragraphs yields the following table of projected annual emissions.

Pollutant	**Factor (Lb/MMBTU)**	**Emissions (TPY)**
CO	0.325	11,270
NO_X	0.14	4,855
SO_2	0.59	20,460
PM_{10}	0.0485	1,682
$PM_{2.5}$	0.00835	290
VOC	0.00363	126
Lead	2.441×10^{-6}	0.085
Fluorides	1.7645×10^{-3}	61.2
Sulfuric acid mist	2.275×10^{-4}	7.89
CO_2	206.1	7,147,136
CH_4 (as CO_2e)	0.509	17,655
N_2O (as CO_2e)	1.093	37,909

Use of projected actual emissions allows increases in emissions due to demand increase (PROMOD) that could have been accommodated by the facility during the baseline years to be excluded from the calculations. The demand increase of 69,356,000 minus 67,168,869 is 2,187,131. Using the baseline emission factors, the increase in emissions that may be excluded are shown in the following table.

Pollutant	**Factor (Lb/MMBTU)**	**Emissions (TPY)**
CO	0.0305	33.4
NO_X	0.386	422
SO_2	0.59	645
PM_{10}	0.0485	53.04
$PM_{2.5}$	0.00835	9.13
VOC	0.00363	3.97
Lead	2.441×10^{-6}	0.003
Fluorides	1.7645×10^{-3}	1.93
Sulfuric acid mist	2.275×10^{-4}	0.25
CO_2	206.1	225,384
CH_4 (as CO_2e)	0.509	557
N_2O (as CO_2e)	1.093	1,195

Finally, projected annual emissions, less baseline actual emissions and less excluded emissions, are compared with the PSD significance threshold in the following table.

Pollutant	Projected	Baseline	Excluded	Net	PSD Threshold	Significant?
CO	11,270	1,024	33.4	10,213	100	Yes
NO_X	4,855	12,964	422	-8,531	40	No
SO_2	20,460	19,815	645	0	40	No
PM_{10}	1,682	1,629	53.04	0	15	No
$PM_{2.5}$	290	280	9.13	0	10	No
VOC	126	122	3.97	0	40	No
Lead	0.085	0.082	0.003	0	0.6	No
Fluorides	61.2	59.3	1.93	0	3	No
Sulfuric acid mist	7.89	7.64	0.25	0	7	No
GHG	7,202,700	6,975,565	227,136	0	75,000	No

Because only NO_X and CO have non-zero net changes, the next table summarizes project-wide PSD threshold analysis, posting data for only the two named pollutants.

Pollutant	Projected	Baseline	Excluded	Net	PSD Threshold	Significant?
CO	11,634	1,453	22	10,159	100	Yes
NO_X	6,184	14,911	372	-9,099	40	No

Although the Unit 2 portion of the project does not exceed the significance threshold, the fact that the entire project is significant for CO means that all equipment in the project must demonstrate BACT for CO. BACT discussions for Unit 2 and for Units 3 and 4 follow.

BACT
UNIT 2

The Northeastern Unit 2 and Units 3 and 4 Low-NO_x Burner and Over-Fire Air (LNB/OFA) project meets the definition of a major modification, because the net increase in emissions exceeds the PSD significance level for CO. A PSD major modification must undergo a Best Available Control Technology (BACT) analysis for which there is a significant pollutant net emissions increase. This BACT analysis is based on current technology as well as environmental, energy, and economic factors. An electric generating unit (EGU) boiler affects energy availability, the economy, and the environment in the surrounding area. There are considerations among these effects such that the mitigation or reduction of one effect may be accompanied by the increase of another. The purpose of a BACT analysis is to determine the lowest emission rate while balancing the considerations of technical feasibility, energy impacts, and economics. BACT is generally defined in these 40 CFR 52.21(j) as

> *an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any source which on a case-by-case basis is determined to be achievable taking into account energy, environmental and economic impacts and other costs.*

In a memorandum dated December 1, 1987, the U.S. Environmental Protection Agency (US EPA) stated its preference for a "top-down" analysis. The five basic steps of a top-down BACT review procedure according to the *New Source Review Workshop Manual* follow.

Step 1. Identify all control technologies

Step 2. Eliminate technically infeasible options

Step 3. Rank remaining control technologies by control effectiveness

Step 4. Evaluate most effective controls and document results

Step 5. Select BACT

An interpretation of the statutory and regulatory BACT definitions contains two core requirements that the ODEQ believes can be met by a BACT determination. First, the BACT analysis must include consideration of the most stringent available technologies, i.e., those which provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decision. In addition, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate less than or equal to the NSPS emission rate for the source. There are no emission standards for CO contained in 40 CFR 60, Subpart D for natural gas-fired boilers.

Carbon monoxide (CO) emissions result from the incomplete combustion of carbon and organic compounds. Incomplete combustion is a function of several parameters including oxygen availability in combustion zones, flame temperature, combustion residence time, and combustor design. Carbon monoxide emissions can be minimized by providing excess oxygen in combustion zones, increasing flame temperature, providing longer combustion residence time, and proper combustor design. However, the techniques for reducing CO emissions provide improved conditions for NO_X formation. Operating parameters and boiler design must be balanced to achieve both low CO and NO_X emissions.

STEP 1. Identify Potential Control Technologies

Emission control of CO is divided into combustion and post-combustion techniques. The potential control technologies for CO emissions on natural gas-fired boilers include catalytic oxidation, external thermal oxidation, and good combustion practices. The first two of these are post-combustion techniques.

STEP 2. Identify Technically Feasible Control Technologies

Good combustion practices are the only feasible CO emissions control technology. Catalytic oxidation and external thermal oxidation are not technically feasible technologies for controlling CO emissions for the reasons described below.

Catalytic Oxidation

Catalytic oxidation is a control technology that uses a catalyst, typically constructed of platinum and rhodium, to convert CO to CO_2. Catalytic oxidation requires the flue gas to pass through the catalyst where CO and oxygen adsorb to the catalyst surface and are converted to CO_2 and water. Catalysts permit chemical reactions to occur at lower temperatures than would typically be required for a non-catalyzed reaction by lowering the activation energy of the reactant species. For a natural gas-fired boiler, a preheater (or equivalent) may be required downstream of the boiler exhaust point and upstream of the catalytic oxidation device to heat the exhaust. Normal operating conditions for CO catalytic oxidation devices are between 600°F and 700°F, but the exhaust temperature from Unit 2 is less than 300°F. Oxygen levels must be kept low in the flue gas as to not promote the formation of NO_X, and the temperature is kept low to improve boiler efficiency. Non-selectivity of the catalyst permits the oxidation of SO_2 to SO_3, as well as CO to CO_2. This may promote the formation of H_2SO_4 emissions and ammonia salts. Increased levels of H_2SO_4 emissions from the oxidation catalyst results in corrosion, causing poor operational performance. Ammonia salts bind to the catalyst surface resulting in reduced performance due to catalyst blinding. Due to the technical problems described above, catalytic oxidation will not be further considered as a feasible control technology for CO emissions.

External Thermal Oxidation (ETO)

ETO is a control technology that involves injecting additional air and heating the flue gas to 1,500 °F to oxidize CO to CO_2 in the flue gas exhaust. The reheat fuel (natural gas) required to reach this high oxidation temperature would result in additional CO emissions. Consequently, there is no evidence that the ETO technology will result in reduced CO emissions. For the reason described above, ETO will not be further considered as a feasible control technology for CO emissions.

Good Combustion Practices

Good combustion practices is a control technology that includes designing and operating the boiler in a manner that limits the formation of CO. Combustion practices and boiler design ensure the proper conditions through several operation or design features. Practices to consider are good air and fuel mixing in the combustion zone, and high temperature and low oxygen levels in the primary combustion zone. Boiler design features to consider are maintaining high boiler thermal efficiency and sufficient flue gas residence time to complete combustion. Boiler design is especially significant for reducing CO emissions because combustion control technologies (e.g., low-NO_X burners) implemented to reduce NO_X create conditions for increased CO formation. Good combustion practices are therefore a balance between minimizing the formation of CO and NO_X, as these emissions are inversely related. Each design feature mentioned in this section provides a key condition which, when properly combined, describes good combustion practices. Natural gas-fired boilers with low-NO_X burners (LNB) are designed to burn the gas slowly by using the minimum amount of combustion air in the primary combustion zone. The combustion zone is under fuel rich conditions as the amount of combustion air is maintained below the requirement for complete combustion. The practice of minimizing the amount of combustion air to the boiler reduces NOx formation; however the primary incomplete combustion product is CO. In the second stage of the boiler, overfire air (OFA) provides the necessary level of oxygen to complete the combustion and convert CO to CO_2, minimizing CO emissions. The availability of oxygen from OFA affects combustion efficiency, CO formation, and NO_X formation. OFA must be controlled in order to balance the effects of excess oxygen and to maintain high boiler thermal efficiency while reducing CO and NO_X formation. Good combustion practices are technically feasible, demonstrated, and are the only accepted technique as a control technology for reducing CO emissions from a natural gas-fired boiler.

STEP 3. Rank the Technically Feasible Control Technologies
The only technically feasible control technology for CO emissions is good combustion practices, thus no ranking is necessary.

STEP 4. Evaluate the Most Effective Controls
The use of good combustion practices presents no significant negative environmental, economic, or energy concerns. In addition, the use of good combustion practices is the only technically feasible option identified by this BACT analysis for reducing CO emissions, thus no additional evaluation is necessary.

STEP 5. Selected Carbon Monoxide BACT Determination
Good combustion practices is the most effective control technology for CO emissions, and is the only control technology considered that is technically feasible. Good combustion practices at an emission rate not to exceed 0.074 lb/MMBtu rolling 30-day average is selected.as BACT for CO emissions.

UNITS 3 and 4

This analysis parallels that for Unit 2 in all but a few places. Only those places reflecting differences are listed here. Assume that all other sections are repeated.

Catalytic Oxidation
Catalytic oxidation is a CO control technology that uses a catalyst, typically constructed of platinum and palladium, to convert CO to CO_2. Catalytic oxidation is a feasible CO control technology for reducing CO emissions from natural gas or oil-fired combustion turbines. However, oxidation catalysts have never been applied to reduce CO emissions for coal-fired boilers because of problematic operating characteristics. Catalytic oxidation requires the flue gas to pass through the catalyst where CO and oxygen adsorb to the catalyst surface and are converted to CO_2 and water. Catalysts permit chemical reactions to occur at lower temperatures than would typically be required for a non-catalyzed reaction by lowering the activation energy of the reactant species. Several characteristics of coal-fired boilers make catalytic oxidation technically impractical, including low excess oxygen levels in the flue gas, low flue gas temperatures, catalyst nonselectivity, catalyst fouling by sulfur and fly ash, and catalyst trace element poisoning. Oxygen levels must be kept low in the flue gas as to not promote the formation of NO_X and the temperature is kept low to improve boiler efficiency. The oxidation catalyst is non-selective, which is a problem for fuels containing sulfur. The non-selectivity of the catalyst permits the oxidation of SO_2 to SO_3, as well as CO to CO_2. This may promote the formation of H_2SO_4 emissions and ammonia salts. The increased levels of H_2SO_4 emissions from the oxidation catalyst results in corrosion to the air preheater and ductwork causing poor operational performance. Ammonia salts bind to the catalyst surface resulting in reduced performance due to catalyst blinding. The high PM and sulfur compound concentrations from

coal-fired units will also contribute to quickly blinding and deactivating the catalyst. Due to the technical problems described above and the lack of demonstrated performance for coal-fired boilers, catalytic oxidation will not be further considered as a feasible control technology for CO emissions.

External Thermal Oxidation (ETO)
ETO is a CO control technology that involves injecting additional air and heating the flue gas to 1,500 °F to oxidize CO to CO_2 in the flue gas exhaust. The reheat fuel (natural gas) required to reach this high oxidation temperature would result in additional CO emissions and consequently there is no evidence that the ETO technology will result in reduced CO emissions. Additionally, ETO is typically not recommended for exhaust streams containing sulfur, as the ETO technology may promote additional SO_2 formation. ETO has never been required or demonstrated on a coal-fired boiler. For the reasons described above, ETO will not be further considered as a feasible control technology for CO emissions.

Good Combustion Practices
Good combustion practices is a control technology that includes designing and operating the boiler in a manner that limits the formation of CO. Combustion practices and boiler design ensure the proper conditions through several operation or design features. Practices to consider are good air and fuel mixing in the combustion zone, and high temperature and low oxygen levels in the primary combustion zone. Boiler design features to consider are maintaining high boiler thermal efficiency and sufficient flue gas residence time to complete combustion. Boiler design is especially significant for reducing CO emissions because combustion control technologies (e.g., low-NO_X burners) implemented to reduce NO_X create conditions for increased CO formation. Good combustion practices are therefore a balance between minimizing the formation of CO and NO_X, as these emissions are inversely related. Each design feature mentioned in this section provides a key condition which when properly combined, describes good combustion practices. Pulverized coal fired boilers with low-NO_X burners are designed to slowly burn the coal by using the minimum amount of combustion air in the primary combustion zone. The combustion zone is under fuel rich conditions as the amount of combustion air is maintained below the requirement for complete combustion. The practice of minimizing the amount of combustion air to the boiler reduces NO_X formation; however the primary incomplete combustion product is CO. In the second stage of the boiler, overfire air (OFA) provides the necessary level of oxygen to complete the combustion and convert CO to CO_2, minimizing CO emissions. The availability of oxygen from OFA affects combustion efficiency, CO formation, and NO_X formation. OFA must be controlled in order to balance the effects of excess oxygen and to maintain high boiler thermal efficiency while reducing CO and NO_X formation. Good combustion practices are technically feasible, demonstrated, and are the only accepted technique as a control technology for reducing CO emissions from a coal fired boiler.

STEP 3. Rank the Technically Feasible Control Technologies
The only technically feasible control technology for CO emissions is good combustion practices, thus no ranking is necessary.

STEP 4. Evaluate the Most Effective Controls
The use of good combustion practices presents no significant negative environmental, economic, or energy concerns. In addition, the use of good combustion practices is the only technically feasible option identified by this BACT analysis for reducing CO emissions, thus no additional evaluation is necessary.

STEP 5. Selected Carbon Monoxide BACT Determination
Good combustion practices is the most effective control technology for CO emissions, and is the only control technology considered that is technically feasible. Good combustion practices at an emission rate not to exceed 0.325 lb/MMBtu rolling 30-day average is selected as BACT for CO emissions.

NSPS, 40 CFR Part 60 [Only Subparts D, Dc, and GG Applicable]
Subpart D (Fossil Fuel-Fired Steam Generators)
Affected sources have a design heat input capacity greater than 250 million Btu/hr (MMBTUH), and must have commenced construction after August 17, 1971. The boiler associated with Unit 1 was replaced by gas turbines, although the steam turbine remains in place. Unit 2 exceeds the 250 MMBTUH threshold, but commenced construction much earlier than its start-up date of 1970, and is not an affected source. The auxiliary boiler for units 1 and 2 is rated at 220 MMBTUH, below the threshold. Thus, none of these units is an affected source.

Construction of Units 3 & 4 and their auxiliary boiler commenced in 1974. Units 3 and 4 are each rated at 4,775 MMBTUH, and are subject to this subpart. The auxiliary boiler for Units 3 and 4 is rated at 239 MMBTUH, which is less than the threshold, and is not subject to Subpart D. Standards to be met by Units 3 and 4 are as follow.

- 40 CFR 60.42 sets a particulate matter emission limit of 0.10 lbs/MMBTU and prohibits opacity in excess of 20%, except for one six-minute period per hour of not more than 27%.
- 40 CFR 60.43 sets a sulfur dioxide limit of 1.2 lbs/MMBTU for solid fuel and 0.8 lbs/MMBTU for liquid fuel, and sets a pro-ration formula for combined fuels. Compliance is based on total fuel use.
- 40 CFR 60.44 sets a nitrogen oxides limit of 0.20 lbs/MMBTU for gaseous fossil fuel, 0.30 lbs/MMBTU for liquid fossil fuel, and 0.70 lbs/MMBTU for solid fossil fuel. It also sets limits for wood residue, lignite, and combinations of these with other fuels, but this facility cannot burn such fuels. The standard is pro-rated in the instance of simultaneous combustion of different fuels.
- 40 CFR 60.45 establishes monitoring criteria, including the operation of continuous monitoring systems for opacity, sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide.
- 40 CFR 60.46 describes test methods in detail, including Appendix A Reference Methods to be used, general requirements per 40 CFR 60.8, and factors to be used in calculations.

As demonstrated in the Emissions section above, the facility is and will remain in compliance with the limits set in 60.42, 60.43, and 60.44. The continuous emissions monitoring system (CEMS) installed to demonstrate compliance with 40 CFR 75 satisfies the criteria of 60.45 and

60.46. Testing demonstrating compliance was performed on May 11 and June 14, 2006, as discussed in the "Testing" portion of Section VIII (Compliance) below.

Subparts Da and Db (Electric Utility and Small Steam Generating Units)

The earliest construction date under any of these subparts is September 18, 1978. Most of the steam generating units (of any size) commenced construction before this date, and they are not affected sources under either of the subparts. Permitted activities under 2003-410-TVR (M-3) and 2003-410-C (M-4) do not result in increase of pollutants subject to standards of Da, so Unit #2 continues not to be an affected source under this subpart. Combined cycle gas turbines with such capacity are affected sources only if fuel combustion in the heat recovery unit exceeds the 250 MMBTUH level. Only 99 MMBTUH is added in the HRSG, so this facility is not subject to Da or Db. Note also the following discussion of Subpart Dc.

Subpart Dc (Small Industrial-Commercial-Institutional Units)

This affects steam generating units with a design capacity between 10 and 100 MMBTUH heat input and which commenced construction or modification after June 9, 1989. The turbine project fits the definition of "combined cycle system" and the HRSG units fit the definition of "steam generating unit" as both are found in 40 CFR 60.41c, so the duct burners are subject to Dc. Particulate and SO_2 standards are not set for gas-fired units. The only applicable standards are initial notification (§60.48c(a)) and a requirement to keep records of the fuels used (§60.48c(g)).

Subparts K, Ka, Kb (VOL Storage Vessels)

There are eleven tanks to consider. The earliest effective date of any of these subparts is June 11, 1973. Five of the hydrocarbon storage tanks were constructed before that date, and are not affected sources. Those five tanks are: #3, with a capacity of 4,200,000 gallons of No.2 fuel oil; #5, with a capacity of 8,459 gallons of natural gas condensate; #8, with a capacity of 9,000 gallons of lube oil; and #9 and #10, each with a capacity of 13,860 gallons of lube oil.

Tank #1 may have been constructed after June 11, 1973, and certainly before May 19, 1978, the pertinent dates for Subpart K. Its capacity of 33,850 gallons of oil is less than the 40,000 gallon threshold of 40 CFR 60.110(a), and it is not an affected source.

The pertinent dates for Ka are after May 18, 1978, and before July 23, 1984. Four tanks have construction dates within that period, namely: #2 and #4, each with a capacity of 13,860 gallons of oil; and #6 and #7, each with a capacity of 13,860 gallons of lube oil. Each tank capacity is less than the 40,000-gallon threshold of 40 CFR 60.110a(a), and none is an affected source.

Anything constructed after July 23, 1984, may fall within the purview of Kb. Tank #11, a 2,000-gallon gasoline tank, was constructed in 1993. Its capacity is less than the 75 m^3 (19,813 gal) threshold stated in 40 CFR 60.110b(a), and the tank is not an affected source.

Subpart Y (Coal Preparation Plants)

The facility handles more than 200 tons of coal per day, and has coal storage systems and coal processing and conveying equipment, which are affected sources per 40 CFR 60.250(a). Construction was commenced before the effective date of October 24, 1974, given in 40 CFR 60.250(b), so Subpart Y is not applicable to this facility.

Subpart GG affects stationary gas turbines with a heat input at peak load of greater than or equal to 10.7 gigajoules per hour (10 MMBTUH) based on the lower heating value (LHV) of the fuel and that commenced construction, reconstruction, or modification after October 3, 1977. The new turbines have LHV heat input capacities of 1,712 MMBTUH at peak load and are subject. The turbines are governed by 40 CFR 60.332(b) and must satisfy the NO_X standard set forth in §60.332(a)(1). As applied to these turbines, the formula yields an upper limit of 100 ppmvd. For NO_X emissions, the BACT requirement of 15 ppmvd is more stringent than Subpart GG and is applicable. Testing fuel for nitrogen content was addressed in a letter dated May 17, 1996, from EPA Region 6. Monitoring of fuel nitrogen content shall not be required when pipeline-quality natural gas is the only fuel fired in the turbine.

Sulfur dioxide standards specify that no fuel shall be used that 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.
Subpart KKK (Equipment Leaks of VOC from Onshore Natural Gas Processing Plants)
The facility has a tank to collect condensate, but does not engage in natural gas processing.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are small emissions of some regulated pollutants, including 0.04 lbs/hr and 0.18 TPY of arsenic, 0.01 lbs/hr and 0.06 TPY of beryllium, and 0.01 lbs/hr and 0.06 TPY of mercury.
Subparts N, O, and P (Inorganic Arsenic from Glass Manufacturing, Primary Copper Smelters and Arsenic Trioxide and Metallic Arsenic Production)
Electric generating facilities are not an affected source under any of these subparts.
Subparts C and D (Beryllium and Beryllium Rocket Motor Firing)
Electric generating facilities are not an affected source under either of these subparts.
Subpart E (Mercury)
Electric generating facilities are not an affected source under this subpart.

NESHAP, 40 CFR Part 63 [Not Applicable at Present]
Subpart Q (Industrial Process Cooling Towers) All facilities operated by this company ceased using chrome in cooling water nearly three decades ago.
Subpart ZZZZ (Reciprocating Internal Combustion Engines or RICE). The two oil-fired emergency generators qualify as "emergency stationary RICE" per the definition found in 40 CFR 63.6675 and are exempt from this MACT per 40 CFR 63.6590(b)(3).
Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters at major sources of HAPs. EPA has published various actions regarding implementation of this rule as outlined following.

- September 13, 2004 EPA promulgated standards for major sources
- June 19, 2007 US Court of Appeals for the district of Columbia vacated and remanded the standards
- March 21, 2011 EPA promulgated new standards
- May 18, 2011 EPA published notice of delay of the effective dates until judicial review or EPA reconsideration is completed, whichever is earlier
- January 9, 2012 DC Circuit Court vacated EPA's May 18, 2011, stay of the regulation. The vacatur means the Boiler MACT is effective immediately. Compliance dates are given in 40 CFR 63.7495. EPA will use its enforcement discretion to send new and

existing sources a "no action assurance letter" indicating that they are not required to submit administrative notifications to permitting agencies signifying that they are subject to the Boiler MACT as issued on March 21, 2011.

- July 18, 2012 EPA announced that it is extending the "No Action Assurance" issued on March 13, 2012, to apply to the deadline for submitting the "Notification of Compliance Status" regarding initial tune-ups in the final Boiler Area Source rule. The agency emphasized that this applies only to the requirement to submit the Notification of Compliance Status for the initial tune up and not to any other provisions of the area source rule. EPA also announced that it is amending the expiration date of the March 13, 2012, "No Action Assurance" so that it will expire when the final Boiler Area Source reconsideration rule is issued and becomes effective or December 31, 2012, whichever is earlier.

Section 112(j) of the Clean Air Act addresses situations where EPA has failed to promulgate a standard as required under 112(e) (1) and (3). Section 112(j) requires case-by-case MACT determination applications to be submitted to the permitting authority within specified time frames. Because 112(j) appeared to address only situations where EPA has failed to promulgate standards and not situations in which complete rules were subsequently vacated, confusion existed as to the requirements for these sources. On March 30, 2010, EPA proposed a rule to amend 112(j) to clarify what applies under 112(j). In the proposed rule, EPA clarifies that the intent was that vacated sources should be treated similar to sources where EPA has failed to promulgate a standard. The rule, as proposed, will require case-by-case MACT applications to be submitted to the permitting authority within 90 days after promulgation of these amendments or by the date upon which the source's permitting authority requests such application. Compliance with this subpart will be determined based on the requirements of the amended 112(j).

CAM, 40 CFR Part 64 [Applicable]

This part applies to any pollutant-specific emissions unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 18, 1998, that addresses "large emissions units," or any application that addresses "large emissions units" as a significant modification to an operating permit, or for any application for renewal of an operating 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 or 10/25 TPY of a HAP

Application for the initial Title V permit was submitted before April 19, 1998, and the facility was exempt from CAM for the first permit term. Units 3 and 4 have particulate emissions standards, have potential emissions in excess of 100 TPY, and have those emissions controlled by ESPs. CAM is required with respect to particulate emissions from Units 3 and 4. A discussion in the current operating permit memorandum concludes that PSO may use the method outlined in Specific Condition #13 of that permit.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
The facility uses commercial natural gas fuel, which is comprised of mainly methane, a listed substance in CAAA 90 Section 112(r). However, this substance is not stored on-site. The small quantity that is in the pipelines on the facility grounds is much less than the 10,000-pound threshold quantity (TQ) and therefore is excluded from all requirements, including the Risk Management Plan (RMP). Hydrazine and ammonia are also stored on-site, but in amounts well below the TQ. Chlorine is no longer used or stored. The following table presents a rough estimate of the amount of each material. The RMP was submitted to EPA Region 6 in a timely fashion and assigned EPA ID# 100000011603. More information on this federal program is available from the web page: *www.epa.gov/ceppo*

Material	CAS #	Storage Capacity (lbs)	TQ (lbs)
Hydrazine	302-01-2	< 50	15,000
Ammonia	7664-41-7	600	10,000

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
Acid Rain renewal Permit No. 2009-470-ARR2 was issued on May 30, 2010, and will continue as a separate permit.

Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
SO_2 initial allowances as published in 40 CFR 73.10 are listed in Permit No. 2009-470-ARR2.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
Certification testing has been completed for the CEM system required for each unit, and EPA issued an approval certification on February 5, 1997, for Units 1 and 2, and on October 9, 1996, for Units 3 and 4.

Acid Rain, 40 CFR Part 76 (Phase I NO_X requirements) [Applicable]
NO_X emission limits are set in Permit No. 2009-470-ARR2.

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. Certified facility personnel perform services on heavy mobile equipment that involve ozone-depleting substances. Motor vehicles are serviced at a local third-party garage by its certified technicians. A certified contractor is used to service all stationary air-conditioning units located on site. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

VIII. COMPLIANCE

Inspection
A full compliance evaluation was conducted by Brandie Czerwinski, Environmental Programs Specialist from the DEQ Regional Office at Tulsa on June 15, 2012. Although questions were raised, none was of sufficient import to prevent issuance of this construction permit. There is no need for an additional inspection at this time.

Testing
Testing required under NSPS Subparts A and D and under Acid Rain provisions has been performed on a timely and continuing basis. The most recent RATA testing was performed for Units 1A and 1B in July, 2012. Unit #4 testing on February 1, 2012 demonstrated compliance with limits on visible emissions and particulate matter. Unit #3 testing on March 24, 2011 demonstrated compliance with limits on visible emissions and particulate matter.

Tier Classification and Public Review
This application has been determined to be **Tier II** based on the request for a construction permit for a significant modification to a Part 70 source. Notice of Application for a major source construction permit was published in the Tulsa Daily World on June 20, 2012. The application was made available for public review at the Central Library of the Tulsa City/County Library at 400 Civic Center, Tulsa. A notice of availability of the Draft permit for review was published in the Tulsa Daily World on June 13, 2013. Copies of the application and of the draft permit were made available at the Catoosa Public Library. Information on all permit actions is available for review by the public in the Air Quality Section of the DEQ web page: *www.deq.state.ok.us*.

No comments on the draft were received and EPA offered no comments during its concurrent review.

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 owns the property.

Fee Paid
Modification of a Part 70 source construction permit fee of $5,000.

IX. SUMMARY

Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues concerning this facility that would prevent issuance of the permit. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

American Electric Power **Permit Number 2003-410-C (M-4) PSD**
Public Service Company of Oklahoma
Northeastern Power Station

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on June 15, 2012, a supplemental submitted October 22, 2012, and with additional information submitted on various later dates. The Evaluation Memorandum dated July 15, 2013, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction and continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emission limitations for each point. Where these limitations conflict with those of Specific Condition No. 5 below, the more stringent limitation applies.

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

A. EUG 1

EUG 1 Gas Turbines and Heat Recovery Steam Generators (HRSG)

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
1	1A	GE MS7001FA S/N 297510	160	1684*	Jan. 2000
1	1B	GE MS7001FA S/N 297511	160	1684*	Jan. 2000

Each turbine exhausts to a 99 MMBTUH Nooter-Erikson HRSG (duct burner). Steam generated by turbine hot exhaust, with additional heat from the HRSG, drives the old steam turbine.

* Under certain operating conditions, the heat input of each turbine may be increased to 1903 MMBTUH.

Each Combustion Turbine without Duct Burners

Pollutant	**lbs/hr**	**TPY**	**ppmvd [1]**
NO_X	108	418	15
SO_2	26.8	5.19	
PM_{10} [2]	20.9	81.1	
VOC	0.40	1.49	
CO	51.7	198	12
H_2SO_4	2.05	0.24	

1) NO_X and CO concentrations: parts per million by volume, dry basis, corrected to 15% oxygen. These concentrations shall not be exceeded except during periods of start-up, shutdown or maintenance operations. **Start-up** begins when fuel is supplied to the Gas Turbine and ends when the gas turbine reaches Mode 6 (as directed by the control system). **Shutdown** begins when the turbine exits Mode 6 and ends with the termination of fuel flow to the turbine, or when the gas turbine returns to Mode 6. Compliance with this condition shall include recordkeeping to demonstrate actual hours in each of start-up and shutdown modes for each CT.

2) Total PM (front and back halves)

When monitoring shows emissions in excess of the limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9.

Each Combustion Turbine with Duct Burners

Pollutant	lbs/hr	TPY
NO_X	117	457
SO_2	28.2	5.50
PM_{10} *	21.9	85.5
VOC	0.50	1.92
CO	60.6	237
H_2SO_4	2.16	0.25

* Total PM (front and back halves)

Compliance with these emission limits shall be demonstrated by fuel usage. Usage of only commercial-grade natural gas is limited to 14,751,840 MMBTU per year at each combustion turbine and 867,240 MMBTU per year at each HRSG set of duct burners.

B. EUG 2

Boiler Unit 2 is considered "grandfathered" (constructed prior to any applicable rule). There are no hourly or annual limits applied to this unit under Title V, however it is limited to existing equipment as is and to maintain compliance with the NAAQS. After construction of the low-NO_X/overfire air project at Unit #2, the unit will be subject to emission limits for CO and NO_X. The BACT emission limits are 0.074 lbs/MMBTU for CO rolling 30-day average and 0.27 lbs/MMBTU rolling 30-day average for NO_X. CO compliance shall be demonstrated using CEMs.

EUG 2 Grandfathered Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
2	2	Babcock and Wilcox UP-60	495	4754	Mar, 1970

C. EUGs 3, 4, Aux 3/4, 6-10, and Coal Pile

EUG 3 Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
3	3	Combustion Engineering #4974 SCRR	490	4775	Apr, 1974

EUG 4 Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
4	4	Combustion Engineering #7174 SCRR	490	4775	Apr, 1974

EUG Aux 3/4 Steam Generator

EU	Point	Make/Model	MW	MMBTUH	Const Date
Aux 3/4	Aux 3/4	Combustion Engineering #3M1004	N/A	239	Apr, 1974

Units 3 & 4 have no current emission limits on CO. After completion of the refined tuning project for Units 3 & 4, there will be BACT emission limits of 0.325 lbs/MMBTU rolling 30-day average for CO demonstrated by CEMs, and 0.14 lbs/MMBTU rolling 30-day average for NO_X. The current limits are shown in the following table.

Source	Pollutant	Lbs/MMBTU
Units 3 & 4	PM	0.1*
	SO_2	1.2
	NO_X	0.7

* NSPS limit measured as filterable (front half) only.

These limits derive from the original construction permit, with the NO_X datum updated to reflect Acid Rain Permit requirements. The 0.7 lbs NO_X/MMBTU emissions represent a NSPS three-hour rolling average limit.

EUG 6 **Rotary Car Dumper Baghouse**

EU	Point	Make/Model	Const Date
6	6	Peabody #03-21	Apr, 1974

EUG 7 **Emergency Reclaim Baghouse**

EU	Point	Make/Model	Const Date
7	7	Peabody #S1-5	Apr, 1974

EUG 8 **Crusher House Baghouse**

EU	Point	Make/Model	Const Date
8	8	Peabody #S2-9	Apr, 1974

EUG 9 **Unit 3 Coal Silo Dust Collector**

EU	Point	Make/Model	Const Date
9	9	Peabody #D2-10	Apr, 1974

EUG 10 **Unit 4 Coal Silo Dust Collector**

EU	Point	Make/Model	Const Date
10	10	Peabody #D2-7	Apr, 1974

EUG Coal Pile

This covers fugitive emissions from wind erosion of the coal pile.

D. EUG Aux 1/2 **Steam Generator**

EU	Point	Make/Model	MW	MMBTUH	Const Date
Aux 1/2	Aux 1/2	Babcock and Wilcox FM 117-97	N/A	220	Mar, 1997

AUXILIARY BOILER 1/2 EMISSIONS

Pollutant	Lbs/hr	TPY
TSP = PM_{10}	1.62	1.06
SO_2	0.13	0.08
NO_X	59.6	39.2
CO	17.9	11.8
VOC	1.17	0.77

E. EUG 11, 12 and 13 Fugitive emissions are estimated based on existing equipment items but do not have a specific limitation.

EUG 11 Coal Handling Fugitives

EUG 12 Fly Ash Handling Fugitives

EUG 13 Bottom Ash Handling Fugitives

F. EUG ChemStore and Plantwide. These sources are not subject to permitting and no emissions are calculated or authorized.

EUG ChemStore Stored Chemicals
This EUG covers various stored chemicals, including hydrogen, ammonia, and hydrazine.

EUG Plantwide Entire Facility
This EUG is established to cover all rules or regulations which apply to the facility as a whole.

2. Compliance with the authorized emission limits of Specific Condition 1 shall additionally be demonstrated by adherence to the two operating scenarios described as follows, where % sulfur is on an "as-burned" basis. Both scenarios assume base-loading on coal; that is, with Units 3 and 4 operating 100% on coal. Under these scenarios, auxboiler 3/4 operates under a 10% annual capacity factor. Units 3 and 4 are primarily coal-fired, with natural gas, #2 fuel oil, and co-firing of coal and natural gas as secondary fuels. The flexibility of using those secondary fuels is implied within both scenarios.

	Units 1A & 1B		Unit 2		Units 3/4
Scenario	**Fuel**	**Oil % Sulfur**	**Fuel**	**Oil % Sulfur**	**Fuel**
1	100% NG	NA	50% Oil/50% NG	≤0.4	100% Coal
2	100% NG	NA	100% NG	NA	100% Coal

The permittee may operate individual units as appropriate. Emission calculations shall use the best available source, such as current CEMs data, the most recent stack testing results, AP-42 emission factors, or other approved emission factors (such as EPRI, etc.). The word "coal" includes the use of petroleum coke (pet coke) as an alternate or blended fuel. CEM data shall be used to demonstrate that the SO_2 limit of Specific Condition #1 is not exceeded while pet coke is being used. Compliance with the authorized emission limits for Auxboiler 1/2 shall be demonstrated by fuel usage. Annual natural gas consumption shall not exceed 280 MMSCF for Auxboiler 1/2.

3. The permittee shall use natural gas and/or oil as required by the operating scenario under which it is operating. Oil shall have a maximum weight percent sulfur as prescribed in Specific Condition 2. [OAC 252:100-31]

4. The permittee shall be authorized to operate this facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

5. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements as listed in renewal Permit No. 2009-470-ARR2, including the following. [40 CFR 75]

a. Compliance with NO_X emission limit for coal units, as described in the Phase II NO_X Averaging Plan, and SO_2 allowances.
b. Report quarterly emissions to EPA per 40 CFR 75.
c. Conduct RATA tests per 40 CFR 75.
d. Updated QA/QC plan for maintenance of the CEMS.

6. The boilers at Units 3 and 4 are subject to NSPS Subpart D and shall satisfy the following. [40 CFR 60, Subpart D]

a. Particulate matter emissions shall not exceed 0.10 lbs/MMBTU.
b. Opacity shall not exceed 20%, except for one six-minute period per hour of not more than 27%.
c. Sulfur dioxide emissions shall not exceed 1.2 lbs/MMBTU for solid fuel and 0.8 lbs/MMBTU for liquid fuel, with a pro-ration formula for combined fuels. Compliance is based on total fuel use.
d. Nitrogen oxides emissions shall not exceed 0.20 lbs/MMBTU for gaseous fossil fuel, 0.30 lbs/MMBTU for liquid fossil fuel, and 0.70 lbs/MMBTU for solid fossil fuel. The standard is pro-rated in the instance of simultaneous combustion of different fuels.
e. Monitoring criteria include the operation of continuous monitoring systems for opacity, sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide.
f. Test methods are described in detail in 40 CFR 60.46, including Reference Methods to be used, general requirements per 40 CFR 60.8, and factors to be used in calculations.
g. The continuous emissions monitoring system (CEMS) installed to demonstrate compliance with 40 CFR 75 may be used to satisfy (e) and (f).

7. The permittee shall at all times properly operate and maintain all boilers and associated emissions control systems in a manner that will minimize emissions of hydrocarbons or other organic materials. [OAC 252:100-37-36]

8. The permittee shall not replace the modified burners on Unit 2, the low-NO_X concentric firing systems of Units 3 and 4, or the electrostatic precipitators on Units 3 and 4 except by devices of equal or greater control efficiency. NO_X control efficiency of the systems on Units 2, 3, and 4 is set

out in the NO_X emission limits of Specific Condition #1. The PM control efficiency of the ESPs is estimated to be 99.6%.

9. If Unit 2 fires liquid fuel for a period greater than 24 consecutive hours, the permittee shall conduct a visual observation of stack emissions for each subsequent 24-hour period. If any visible emissions are observed, then the permittee shall conduct a six-minute opacity reading by a certified observer in accordance with EPA Reference Method #9. The permittee shall maintain records of the date and time of observation, stack or emission point identification, operational status of the emission unit, observed results and conclusions, and RM 9 results. [OAC 252:100-43]

10. NSPS modification or reconstruction of the Unit 2 boiler may cause it to become subject to further limits and require permitting. The permittee shall maintain Operating and Maintenance records sufficient to demonstrate that this source has not been modified or reconstructed to an extent requiring permitting. [OAC 252:100-8, 40 CFR 60 Subpart D]

11. A Compliance Assurance Monitoring (CAM) Plan is required for mass emissions from Units 3 and 4, with respect to both the NSPS Subpart D limit of 0.10 lb/MMBTU for filterable particulate and the OAC 252:100-19 limit of 0.125 lbs/MMBTU for total particulate (filterable and condensable, or front half and back half). Simultaneous measurements of particulate emissions and opacity for each generating unit have indicated that the facility can reasonably expect to be in compliance with both NSPS and state limits on particulate emissions when opacity is no greater than 20%. Specific Condition 13 addresses additional performance testing to collect further supporting data for this position. The following table addresses specific issues within the plan. A description of corrective actions follows the table. The facility does not believe that monitoring ESP parameters is a very good indicator of emission compliance. Activities concerning the ESP operation are considered within the framework of corrective actions.

I. Indicator	Opacity.
Measurement Approach	Exhaust gas opacity is measured continuously using an inline transmissometer. RM 9 readings will be performed in the event of COM failure.
II. Indicator Range	The range is continuous from zero to 100%. Excursions trigger corrective action, logging, and reporting in the semi-annual report.
III. Performance Criteria	
A. Data Representativeness	Accuracy is ± 2% of opacity maximum.
B. QA/QC Practices and Criteria	As required by 40 CFR 75, Appendix B.
C. Monitoring Frequency	Opacity is measured continuously, although RM 9 readings will be performed intermittently upon COM failure.
D. Data Collection Procedures	Rolling hourly averages are calculated and stored electronically. Excursions trigger corrective action, logging, and reporting in the semi-annual report.
E. Averaging Period	One-hour rolling average.

A significant opacity increase, or excursion, is any average opacity value greater than 20% during any rolling one-hour period. This plan does not apply to periods of start-up, shutdown, and maintenance activities, nor during one 6-minute average per hour of up to 27% opacity, nor during those periods caused by monitor malfunction, calibration, or maintenance, or those occurring during equipment or source malfunctions, etc. Actions to be taken upon noting a significant increase include reviewing COMS data, transformer rectifier status, including voltage, current, and operating parameters, verifying the increase, identifying the cause of the increase, returning any tripped TR sets to service, and checking the ash removal system. Normal operation of the ESP includes recordkeeping for voltage and current levels. Routine actions concerning the ESP shall be emphasized when corrective action is taken. These actions include:

a) Adjusting the TR set parameters to optimize operation, particularly when the ESP is operating at reduced power;
b) Tagging for repair and/or adjustment, as appropriate, any individual TR sets that are out of service or are not operating at optimum levels;
c) Initiating or adjusting ESP rapping procedures as necessary; and
d) Taking any other corrective actions necessary to maintain or return opacity to normal operating levels.

Actions taken under this Condition will comply with the appropriate underlying rules or regulations, including, but not necessarily limited to, 40 CFR 60 Appendix A, 40 CFR 60 Appendix B: Specification 1, 40 CFR 75 Appendix B, and OAC 252:100-43.

12. The permittee shall utilize a portable baghouse or equivalent control to reduce opacity of emissions during off-line sandblasting of the ESPs and/or boilers at Units 3 and 4.
[Consent Order 06-316]

13. Performance testing to establish PM_{10} emissions from Units 3 and 4 shall be performed at least once before each succeeding Title V renewal application is due. Appropriate Reference Method testing to determine that filterable (front half) emissions are in compliance with the Subpart D standard of 0.10 lb/MMBTU and that combined filterable and condensable (back half) emissions are in compliance with the OAC 252:100-19 standard of 0.125 lbs/MMBTU shall be used. Testing shall be performed in a timely manner such that results of the performance tests and opacity readings taken during the tests can be provided with the Title V renewal application. Results from this testing shall also provide further data confirming the assumptions underlying the CAM plan offered in Specific Condition #11. [OAC 252:100-43; 40 CFR 64]

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

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

15. Under operating permit 2004-410-TVR (M-3) permittee was required to calculate and maintain a record of the annual emissions, in TPY on a calendar year basis, for a period of 5 years following resumption of regular operations after the installation of low-NO_X concentric

firing systems on Units 3 and 4 as required by OAC 252:100-8-36.2(c)(3). Permittee shall comply with reporting requirements of OAC 252:100-8-36.2(c)(4). Upon completion of the refined tuning project that is authorized in this permit, Specific Condition No. 15 of Permit No. 2003-410-TVR (M-3) will be voided. [OAC 252:100-8-36.2(c)]

16. The following records shall be maintained on-site. All such records shall be made available to regulatory personnel upon request. These records shall be maintained for a period of at least five years after the time they are made. [OAC 252:100-43]

a. Total usage of each type of fuel for each boiler (monthly and cumulative 12-month rolling)
b. Sulfur content of fuel oil (on an as-burned basis and each new delivery)
c. Emissions data as required by the Acid Rain Program
d. RATA test results from periodic CEMS certification tests
e. Operations and maintenance log for Unit 2 sufficient to demonstrate compliance with Specific Condition #10
f. Opacity observations as required by Specific Condition #9
g. Maintenance and visual inspection of particulate filter systems (weekly)
h. Manufacturer's recommended maintenance of ESPs
i. A record of the Scenario under which the facility is operating (continuously)
j. Hours each CT spends in start-up and in shutdown, as required by Specific Condition #1 (A) EUG 1.
k. CAM records, as referenced in Specific Condition #11
l. Data demonstrating compliance with NSPS Subpart GG, as required by Specific Condition #14.
m. Actual emissions of carbon monoxide compared with projected emissions of carbon monoxide, per Specific Condition #15, as long as that condition is in effect.

17. The following records shall be maintained on-site to verify insignificant activities. [OAC 252:100-43]

a. Throughput for fuel storage/dispensing equipment operated solely for facility owned vehicles, if throughput is less than 2,175 gallons per day, averaged over a 30-day period (annual total).
b. Capacity of all storage tanks with a capacity of 39,894 gallons or less storing a fluid with a true vapor pressure less than 1.5 psia (for each delivery of fluid, the type and quantity).
c. Operation of each stationary reciprocating engine burning natural gas, gasoline, aircraft fuels, or oil, used for emergency power generation less than 500 hours per year (annual total hours).
d. Gallons of spilled petroleum liquids added to the coal pile.
e. Amount and disposition of fly ash handled by Boral or its successors.
f. Records for any other activity, demonstrating that emissions are less than 5 TPY.

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards (“NSPS”) under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants (“NESHAPs”) under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer’s instructions and in accordance with a protocol meeting the requirements of the “AQD Portable Analyzer Guidance” document or an equivalent method approved by Air Quality.
[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.
[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

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

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

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.
[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

   (a) 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;
   (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
   (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
   (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]
C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must

comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).
(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 C.F.R. § 70.8(d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by

DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

PART 70 PERMIT

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

Permit No. 2003-410-C (M-4) PSD

American Electric Power,

having complied with the requirements of the law, is hereby granted permission to add low-NO_X burners and overfire air to Unit #2 and to perform refined tuning of the low-NO_X concentric firing system on Units 3 and 4 at the Public Service Company of Oklahoma Northeastern Power Station, located in Section 4, T22N, R15E, one mile south of Oologah, Rogers County, Oklahoma,

subject to standard conditions dated July 21, 2009, and specific conditions, both attached.

This permit shall expire 18 months from the date of issuance, except as authorized under Section VIII of the Standard Conditions.

______________________________ ______________________

Director, **Date**
Air Quality Division

P. Mark Barton, Plant General Manager
American Electric Power
P.O. Box 399
Oologah, OK 74053

Re: Low-NO_X/overfire air for Unit 2 and refined tuning of Low-NO_X concentric firing systems for Units 3 and 4 at PSO Northeastern Power Station
Permit No. **2003-410-C (M-4) PSD**

Dear Mr. Barton:

Enclosed is the construction modification to your Title V operating permit, concerning the pollution reduction projects referenced above. Please note that this permit is issued subject to standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emission inventory for this facility. An emission inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emission Inventory Staff at 405-702-4100.

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

Sincerely,

Phillip Fielder
AIR QUALITY DIVISION