OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **August 17, 2016**

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

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

THROUGH: Jian Yue, P.E., New Source Permits Section

FROM: Iftekhar Hossain, P.E., New Source Permits Section

SUBJECT: Permit No. **2012-918-TVR2 (M-1)**
American Electric Power
Public Service Company of Oklahoma (PSO)
Northeastern Power Station (Facility ID: 212)
Section 4, T22N, R15E, Rogers County, Oklahoma
Direction: From US 169 and OK 88 approx. one mile south of Oologah, east on OK 88 roughly 200 yards to driveway at 36.43783° N, 95.70537° W.

SECTION I. INTRODUCTION

Northeastern Power Station (Northeastern) generates electricity using both combustion and steam turbines (SIC 4911). The original Title V permit for this facility was issued on June 30, 1999, and the facility currently operates under Part 70 operating permit No. 2012-918-TVR2 issued on November 18, 2014. The applicant has submitted an application to make minor modification to the current Part 70 permit. In this permit action, the applicant intends to accomplish the following (All EUG Nos. and specific condition (SC) Nos. in this section are referred to the current permit (No. 2012-918-TVR2)):

1. Retire "Unit No. 4", effective April 16, 2016.
2. Remove all Unit No. 4 related text/table/specific conditions (SC) from the memorandum and the permit. Only the language(s) depicting the historic fact(s) about Unit No. 4 will still remain in the memorandum.
3. Remove EUG 4 (Steam Generator) and EUG 10 (Unit 4 Coal Silo (Cascade) Dust Collector) from the memorandum and the permit.
4. Change Auxboiler 1/2 gas consumption in SC #2 in current permit: Annual natural gas consumption shall not exceed 192,720 MMBtu/yr for Auxboiler 1/2, based on operation under a 10% "annual capacity factor" (in order to be consistent with Auxboiler 3).
5. Update SC #4 and SC #21 (new SC #19) to reflect Acid Rain Permit No. 2014-1749-ARR3.
6. Remove SC #9 of current permit, since the Unit No. 3 Activated Carbon Injection, Dry Sorbent Injection, and Fabric Filter (ACI/DSI/FF) Project has been completed, and Unit 4 has been retired.
7. Remove SC #13 of current permit, since the Refined Tuning project has been completed.
8. Change the following of SC #17 (new SC #15) of current permit:

(a) In (e) Change "Specific Condition #9" to "Specific Condition #7".
(b) The recordkeeping of (g), (j), and (l) are now void and removed from this permit. Specific Conditions which pertained to the ESPs or the CAM Plan (17g, and 17j) are no longer applicable. Also, Specific Conditions that refer to the CO calculations (17.l), are no longer applicable.

9. Revise the names of the control devices of EUG 6 through EUG 10.
10. Revise/edit the typographical error(s). These actions will not affect any applicable regulation(s) and/or emissions limitations of the permit. These are:
    (a) SC #1: A. EUG 1 - Each Combustion Turbine without Duct Burners: SO_2 and H_2SO_4 lb/hr values corrected to 1.18 and 0.06, respectively.
    (b) SC #1: A. EUG 1 - Each Combustion Turbine with Duct Burners: SO_2 and H_2SO_4 lb/hr values corrected to 1.26 and 0.06, respectively.
    (c) SC #1: B. EUG 2 – "Annual" Reference Method testing – Changed to "once every four operating quarters, as defined in 40 CFR 75".
    (d) SC #1: C. EUG Aux 3 – "Annual" Reference Method testing – Changed to "once every four operating quarters, as defined in 40 CFR 75".
    (e) SC #1: D. EUG Aux 1/2 – "AUXILIARY BOILER 1/2 EMISSIONS – Emissions table corrected to more conservative limits.
    (f) SC #18: Tank #5 is replaced by "the Unit 1 and Unit 2 Gas Yard's Condensate Drip Tank".
    (g) SC #19 (g): Unit No. 4 related condition has been removed.
11. In Permit Memorandum – These actions will not affect any applicable regulation(s) and/or emissions limitations of the permit. These are:
    (a) Update the Process Description to clarify the process.
    (b) EUG ChemStore: Stored Chemicals – Change ammonia stored from 600 lb to 900 lb.
    (c) EUG 1 - Each Combustion Turbine without Duct Burners: Correct SO_2 and H_2SO_4 lb/hr values to 1.18 and 0.06, respectively.
    (d) EUG 1 - Each Combustion Turbine with Duct Burners: Correct SO_2 and H_2SO_4 lb/hr values to 1.26 and 0.06, respectively.

In this permit application, AEP initially also requested to have the option to evaporate leachate via injection into Unit 3. Later on, the applicant withdrew that request as they did not have sufficient, valid, and enough data specific to Northeastern landfill to speciate the emission type and amounts from leachate injection.

It may be noted that there are several modifications of Permit No. 2003-410-TVR. The modifications are designated by M-1, M-2 and so on. In this memorandum, different modifications have been cited in the description and referred to modifications by M-1, M-2 so on, instead of referring to the whole permit number.

SECTION 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 Unit 2 boiler is 100% gas-fueled. The M-6 PSD modification authorizes installation of low-NO_X burners and overfire air (LNB/OFA) on Unit 2.

The boilers providing steam for Unit 3 is primarily coal-fired, with natural gas, #2 fuel oil, and co-firing of coal and natural gas as secondary fuels. Applicant has added low-NO_X concentric firing systems (LNCFS, which is a trademark for the proposed system) consisting of low-NO_X burners (LNB) and separated overfire air (SOFA) to coal-fired Unit 3 in advance of EPA's CSAPR requirements, under operating permit modification 2003-410-TVR (M-3), issued March 8, 2012. This was a major modification, and applicant has refined the system by "Refined Tuning" under the M-6 PSD permit, and performance testing has verified compliance with the NO_x and CO emission limits.

The pollution control project covered by application TVR (M-5) added two injection systems to control emissions of mercury, SO_2 and acid gases, as well as a baghouse that controls PM emissions from the two injection systems and serve as the only control device for existing PM emissions, all at Unit 3. The existing control device for Unit 3 - the Electrostatic Precipitator – which is upstream of the equipment added under the M-5 permit, will serve only as a product recovery device by April 16, 2016.

Two additional boilers serve as auxiliary gas-fired steam generators, one serving Units 2 (Auxboiler 1/2), and another originally serving Units 3 & 4 (Auxboiler 3/4). Beginning April 16, 2016, Auxboiler 3 began serving Unit 3 only. 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 the ash management contractor, thus avoiding a separate Title V permit for that company. Fly ash generated by coal combustion at Northeastern Units 3 was originally captured by an electrostatic precipitator (ESP) and initially stored in a fly ash silo. There have been two options for removal of the fly ash from the silo, although a third option due to the M-5 project will be discussed later in this Memorandum. Either option may be required to handle 100% of the fly ash captured by the ESP, 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 a paved road to exit the plant site.

The second option utilizes a pneumatic trailer for permanent disposal as ash rock. Fly ash is loaded into modified onsite pneumatic tanker trailers using the same chutes as used in option one. The hatches are closed after loading and the truck drives to the landfill area. A water truck moistens the area where the ash is to be deposited. The truck slows to 2 or 3 miles per hour upon arrival at the site and the pneumatic valves are opened, allowing the fly ash to drop from the bottom of the tanker, which has full skirting mounted to contain the fly ash. Deposition occurs for 30 seconds, with no additional air input. A water truck follows immediately behind this deposition, providing additional moisture for the fly ash, both to control dust and also to solidify the ash-water mixture. This mixture is then rolled, spread, and compacted by a motor grader. A water truck follows the grader, watering the area for the next load or for further dust control, as necessary. The weight of the haul truck, water truck, and grader, combined with the number of trips made over the area, further compact the material. The compacted material continues to be watered occasionally to maintain dust control and assist in curing. Eventually, the mixture will cure into "ash rock." Ash rock may remain in the landfill indefinitely, but may be recovered at some future date for other uses.

The third option is for the fly ash to be loaded into open-topped 15-ton capacity trucks with a front end loader, covered and then transported one mile over an unpaved road to the truck wash station. After the truck is manually washed, it travels one mile over a paved road to exit the plant site.

The TVR (M-5) project involves addition of an activated carbon injection (ACI) system to control mercury within the flue gas of Unit #3, followed by the addition of a dry sorbent injection (DSI) system to control acid gases and SO_2 within the flue gas of Unit #3. Both systems were added downstream of the electrostatic precipitator (ESP) for Unit #3. Finally, a fabric filter baghouse (FF) was added downstream of the ACI and DSI systems, to capture particulate emissions from the treated flue gas stream. Powdered activated carbon (PAC) is delivered by differential pressure from trucks to a storage silo. Next, PAC flows to weigh bins, then via pneumatic injection ports into the Unit 3 ductwork, upstream of the fabric filter. The ACI injection rate is expected to be a nominal 250 lb/hr, but depends on system variables. The DSI system involves sodium bicarbonate (SBC), which is delivered by differential pressure from trucks or rail cars to two storage silos. SBC is then screw fed to air classifier mills that feed the SBC pneumatically to injection ports in Unit 3 ductwork upstream of the fabric filter. The SBC injection rate is expected to be a nominal 5,250 lb/hr, dependent upon system variables. Material captured from the fabric filter is referred to as byproduct, and is sent pneumatically to a byproduct storage silo. Byproduct is mixed with flyash and water in a pug mill to reduce dust emissions when loaded onto trucks for hauling to the landfill. Dry byproduct may also be loaded to the truck by a sealed system that sends displaced air into the silo. Each of the four silos has a bin vent filter on top, as do the classifier mills. The filters are for retention of product, only secondarily providing emission control. Fugitive emissions are created by the trucking involved. These efforts to control the named pollutants will result in small increases in emissions of particulates, requiring a minor modification to the existing Part 70 operating permit.

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.

The use of natural gas as ignition fuel has trivial effects on emissions of SO_2 as compared with the effects due to coal. The proposed use of petroleum coke (pet coke) is treated in several parts of this permit. Unit 3 has 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 operates under a 10% annual capacity factor. As indicated, Unit 3 is 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. The duration of actual fuel use in calendar year 2012 follows.

Unit 1A		Unit 1B		Unit 2		Unit 3	
Fuel	Hours	Fuel	Hours	Fuel	Hours	Fuel	Hours
NG	5,300 (100%)	NG	5,579 (100%)	NG	3,861 (100%)	Coal	7,025 (98.4%)
						NG	113 (1.6%)

Natural gas firing is usually the mode chosen for start-up and flame stabilization for coal-firing at Units 3, and does not generally represent long-term natural gas use. Natural gas can be used in identical fashion for Unit 3 if preparing to burn oil. Although Unit 3 has 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 2012. 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.

SECTION 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

EUG 3 Steam Generator

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

Projects proposed in the M-5 application affected this EUG. As previously operated, exhaust gases from combustion pass through an ESP before exiting the stack. After construction of the control devices proposed by M-5, the products of combustion will pass through the ESP, then receive injections from the ACI and DSI systems, and finally pass through the FF before exiting the stack.

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 **Steam Generator**

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

EUG 6A & 6B **Rotary Car Dumper Baghouses (East and West)**

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

EUG 7 **Emergency Reclaim Water Curtain (Make: "Engart", July 2009)**

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

EUG 8 **Crusher House Water Curtain (Make: "Engart", July 2009)**

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

EUG 9 **Unit 3 Coal Silo (Cascade) Dust Collector**

EU	Point	Make/Model	Const Date
9	9	Peabody #D2-10	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** (The ash management contractor Permit 95-427-O)

EUG 13 **Bottom Ash Handling Fugitives**

EUG 14 **Byproduct Handling Fugitives**

EUG 15 **Bin Vent Filters**

EU	Point	Source	Const Date
15	1	Sorbent silo 1	2/2016
15	2	Sorbent silo 2	2/2016
15	3	Activated carbon silo	2/2016
15	4	Byproduct silo	2/2016
15	5	Classifier mill 1	2/2016
15	6	Classifier mill 2	2/2016

EUG 16 Emergency Engines (for Generators)

EU	HP	Description	Fuel Type	Function	Mfg. Date
GEN 1/2	3,600	General Motors, Model MP45A (Electro-Motive Division MU-Type Power Plant).	Diesel-fired	for service at Units 1 & 2	05/1968
GEN 3	1,476	Detroit Diesel Allison, Model 16V-149T (Supplied by United Engines, Inc., descriptor B/M 6571/6572 M-22C)	Diesel-fired	for service at Unit 3	02/1979

EUG ChemStore Stored Chemicals

Material	CAS #	Stored Quantity	Use
Hydrazine	302-01-2	< 2 gallons	Closed cooling systems & aux boiler
Ammonia	7664-41-7	900 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 ten hydrocarbon storage tanks, a gasoline pump and storage tank, and a fly ash landfill.

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	3	600	27.0′ diameter	1,556,205	250
Aux 1/2	Aux 1/2	168.5	4.5′ diameter	54,287	555
Aux 3	Aux 3	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

SECTION 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. Because of the ESP, TSP is assumed to be PM_{10}, and a MATS factor was applied to estimate the $PM_{2.5}$ 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.

Addition of low-NO_X burners to units 3 and 4 under TVR (M-3) suggested changes in the emission factors used for NO_X and for CO. Applicant stated that no emission rates would be increased by the project, with the possible exception of CO. Although NO_X was expected to decrease, it was taken to remain unchanged as a worst-case assumption. Although applicant expected CO emissions to remain below the AP-42 factor formerly in use, they arbitrarily assumed a slightly higher factor of 0.0333 lb/MMBTU. The facility will continue to comply with existing limits. The project was expected to have no measurable effect on the emissions of any other pollutants.

Emissions for point sources are established as follows. Emissions from Units 1A, 1B, 2, & 3 are calculated based on the discussion 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). Unit 3 has the capability of burning 266 TPH of coal (2.33×10^6 TPY). Unit 4 had 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 surrogates 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. Prior to the TVR (M-3) and (M-6) permits, CEMS data showed that actual emission rates were in the mid-400 lbs/MMCF range. The following tables originally reflected the old value rather than the current "pre-NSPS uncontrolled" value of 280 lbs/MMCF.

The facility is also subject to Acid Rain Renewal Permit No. 2014-1749-ARR3, which establishes a NO_X limit of 0.40 lbs/MMBTU, on an annual average basis through December 31, 2019.

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 is currently grandfathered, Unit 3 has emission limits in terms of lbs/MMBTU on an annual average basis, established in Acid Rain Renewal Permit No. 2014-1749-ARR3. The foregoing discussion of emission factors used in calculations for EUGs 2, 3, Aux 1/2, and Aux 3 is summarized in the following table. To recap the preceding discussion and as a precaution about the proper use of these factors, note the following. First, for calculating estimated hourly NO_X emissions (coal-firing), 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 0.15 lb/MMBTU datum proposed for the M-6 project is a 30-day rolling BART average only. Second, the construction permit for units 3 and 4 did not set limits for CO emissions, but the M-6 project did. 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
$PM_{2.5}$	7.6	1.3	0.039
SO_2	0.6	142S*	12.56
NO_X	459	20	2.30**
CO	84	5	5.33
VOC	5.5	0.76	0.06

***S = sulfur content in percent; **M-6 30-day rolling average**

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.

Pollutant	Emission Factor	Turbine (ea)		Factor	Duct burner (ea)		Totals	
		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	1.18	5.19	<.001	1.41	0.31	56.4	11.0
$PM_{10}=PM_{2.5}$	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	0.06	0.24	Per SO_2	0.11	0.01	4.21	0.50

Pollutant	Units 1A & 1B Lb/hr	Units 1A & 1B TPY	Unit 2 Lb/hr	Unit 2 TPY	Unit 3 Lb/hr	Unit 3 TPY
TSP	43.8	171	35.4	155	64.9	284
PM_{10}	43.8	171	35.4	155	64.9	284
SO_2	1.26	11.0	2.80	12.3	3,702	16,215
NO_X	234	914	2,139	5,622	3,343	2,928
CO	121	474	352	1,541	N/A	6,797
VOC	1.00	3.84	25.6	112	17.7	77.5

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

EMISSIONS FROM AUXILIARY BOILER 1/2 & 3

Pollutant	Emission factor*	213 MCFH Lb/hr	280 MMCFY 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- 9)

Source	Pollutant	Emission factor, Lb/ton*	Coal handled TPH	Coal handled TPY × 10^3	Emissions Lb/hr	Emissions 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}

**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.*

<u>EUG 16 Emergency Engines (for Emergency Generators)</u>

Engine Emission Factors

Name/Model	NO_X (lb/hp-hr)	CO (lb/hp-hr)	SOx (lb/hp-hr)	PM (lb/hp-hr)	VOC (lb/hp-hr)
3,600-hp General Motors, Model MP45A (GEN 1/2)	0.024	0.0055	0.0000121	0.0007	0.000642
1,476-hp Detroit Diesel Allison, Model 16V-149T (GEN 3)	0.024	0.0055	0.0000121	0.0007	0.000642

Emission Factors from US EPA AP-42 (10/96), Table 3.4-1. Sulfur content of diesel fuel: 0.0015%

Potential Hourly Emissions

Emergency Generator	Potential Hourly Emissions				
	NOx	CO	SOx	PM	VOC
	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
GEN 1/2	86.40	19.80	0.044	2.52	2.31
GEN 3	35.42	8.12	0.018	1.03	0.95

40 CFR 63 Subpart ZZZZ: Emergency Generator Emissions

Emergency Generator	Yearly Emissions (based on 100 hours of operation)				
	NOx	CO	SOx	PM	VOC
	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)
GEN 1/2	4.32	0.99	0.002	0.13	0.12
GEN 3	1.77	0.41	0.001	0.05	0.05

PARTICULATE EMISSIONS FROM MATERIAL HANDLING (EUGs 11-15)

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. Emissions from EUGs 11 and 12 were calculated using factors from AP-42 Chapter 11.19. 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 an ash management contractor's permit are now included in this Title V permit. Fly ash collection and transportation from the ESPs is enclosed within the ash handling system 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 the ash handling system 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.

There are PM emissions from handling various materials, including PAC, SBC, and byproduct, with respect to storage and transportation of these new operations. The fabric filter adds another layer of control to that provided by the ESP. Emission calculations for the new operations assume maximum throughput. For instance, each bin vent has a manufacturer's guarantee of 0.01 grains per SCF. Given the annual flow associated with delivery of the particular product, an annual estimate of PM emissions may be made. Hourly usage of each material, the capacity of the haul trucks, and the roundtrip distance traveled, allow for vehicle miles traveled (VMT)) calculations for the SBC and PAC. A similar calculation, based on an estimated 165 tons per day of byproduct may be performed, noting that each trip is divided between 1,100 feet on paved roads and 11,600 feet on unpaved roads. In all cases, 94 days per year are assumed for measurable precipitation. All emissions calculations relating to travel use Equations 1, 2, and 3 from Section 13.2.2 of AP-42. A drop point calculation was made for the landfill, using numbers referenced above and methods shown in Section 13.2.4 of AP-42 (11/06). Details of the various constants, such as the k-factor, are available in the application, but the numbers generated are fairly small, so the following table recites the points involved and their contributions to the overall emissions.

Point ID	Process	Emissions (TPY)		
		PM	PM_{10}	$PM_{2.5}$
Reagent (SBC) handling and delivery				
EUG-15, EU 1	Storage silo 1	0.200	0.168	0.044
EUG-15, EU 2	Storage silo 2	0.200	0.168	0.044
EUG-15, EU 5	Classifier mill separator 1	1.877	1.573	0.414
EUG-15, EU 6	Classifier mill separator 2	1.877	1.573	0.414
PAC handling system				
EUG-15, EU 3	PAC storage silo	0.24	0.20	0.05
Ash/byproduct handling systems				
EUG-14, TP-01	Truck loading	0.079	0.066	0.017
EUG-14, NP-01	SBC & PAC paved roads	0.51	0.10	0.03
EUG-14, NP-02	Byproduct paved roads	0.11	0.02	0.01
	Byproduct unpaved roads	5.48	1.47	0.15
EUG-14, NP-03	Landfill traffic	1.07	0.28	0.03
	Landfill bulldozing	0.58	0.15	0.02
	Byproduct drop point	0.17	0.08	0.03
Totals		**13.33**	**6.64**	**1.47**

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. The current table does not reflect the expected effect of the M-5 project with respect to mercury emissions. Fuel consumption for Unit 3 is 4.78×10^9 BTU/hr and 4.183×10^{13} BTU/yr or 295 TPH and 2,582,100 TPY of coal. 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 Unit 3. The current table does not reflect the expected effect of the M-5 project with respect to HF emissions. 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. Historic potential oil consumption rates for Units 3 and 4 were 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 performed a study of electric utility steam generation that tabulates emissions of those chemicals listed in Section 112 of the Clean Air Act. 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, yielded results shown in previous permits. Better data for hydrogen fluoride and hydrogen chloride were subsequently received per the EPRI study cited above, so this table presents only the hydrogen chloride results, using the average 2008-2009 factor of 464.8 lb/10^{12} BTU.

Unit	Lbs/hr	TPY
#3	2.22	9.7

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.

Pollutant	Emission factor	Emissions		
		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	7.1×10^{-4} lb/MMBTU	1.428	2.856	11.14
Naphthalene	1.4×10^{-1} lb/MMCF	0.276	0.552	2.154
NDMA*	2.3×10^{-4} lb/MMCF	<0.001	0.001	0.004
NMOR*	2.3×10^{-4} lb/MMCF	<0.001	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	<0.001	0.001	0.003
Xylene	2.7×10^{-2} lb/MMCF	0.053	0.106	0.416
Arsenic	4.9×10^{-5} lb/MMCF	<0.001	<0.001	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	7.5×10^{-2}	1.35	5.84
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 7.1×10^{-4} lbs/MMBTU used for natural gas. This factor is 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, and 3, 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		13.0	56.4
Hydrogen fluoride	Coal	16.8	73.5
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
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

Chemical	Fuel	Emissions	
		Lbs/hr	TPY
Selenium	Coal	0.77	3.36
TMA	Gas	<.01	<.01
Toluene	Gas	0.51	2.00
Xylene	Gas	0.11	0.42

**Reflects theoretical estimate; the facility will comply with MATS.*

Greenhouse Gas (GHG) Emissions

Northeastern Power Station is a major source of CO_2 equivalent (GHG) emissions.

SECTION 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 are available which confirm the insignificance of the activities. 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 31,500 gallons, and for the Units 1 and 2 emergency generators, 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.

* Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure of less than or equal to 1.0 psia at maximum storage temperature. PSO has a natural gas condensate tank (#5) with capacity of 8,459 gallons.

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 landfill.
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. The 2012 emission inventory does not show that any diesel or lube oil was added to the coal pile.
k) The fly ash material handling activities contracted to the ash management contractor have emissions calculated at well below 5 TPY, as shown in EUG 12 previously.

SECTION VI. OKLAHOMA AIR POLLUTION CONTROL RULES

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

OAC 252:100-2 (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. Emission inventories were 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	0.008
Unit 3 C.E. boiler	4,775	0.125	0.0146 (oil)
Units 1 & 2 auxiliary boiler	220	0.288	0.008
Unit 3 auxiliary boiler	239	0.282	0.008
Units 1 & 2 3,688-hp generator	124	0.330	0.0146 (oil)
Unit 3 1,476-hp generator	50	0.410	0.0146 (oil)

Section 19-12 limits particulate emissions from new and existing emission points in an industrial process to lb/hr values determined by process weight (see Appendix G). Coal handling calculations used a control efficiency factor of 99.9%. That efficiency has been ignored for this analysis. The following table compares values calculated in Section IV above to the applicable weight-rate limitations.

Source	Emission factor, Lb/ton	TPH	Emissions (Lbs/hr)	
			Actual	Appendix G
Car Dumper	3.098×10^{-3}	2,835	8.78	460
Emergency Reclaim	1.033×10^{-3}	752	0.78	74
Crusher	1.033×10^{-3}	545	0.56	70
Unit 3 Silo	1.033×10^{-3}	301	0.31	63
SBC Silo 1	See Sect VII PSD	2.625	0.17	2.625
SBC Silo 2	See Sect VII PSD	2.625	0.17	2.625
Mill separator 1	See Sect VII PSD	2.625	1.57	2.625
Mill separator 2	See Sect VII PSD	2.625	1.57	2.625
Activated carbon silo	See Sect VII PSD	0.125	0.20	1.02
Byproduct silo	See Sect VII PSD	6.875	0.79	14.8

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.

The Unit 3 stack is equipped with an opacity monitor, are subject to an opacity limit under NSPS Subpart D, and is 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. Some haul roads and the coal yard areas 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, which 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. Unit 3 and auxiliary boilers 1/2 and 3 have been installed since the effective date, and are new equipment. Unit 3 has 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 less than the listed standards for each type of fuel. Addition of the low-NO_X burners were expected to decrease emissions below the already acceptable levels, and the refined tuning approved under M-6 PSD should further decrease emissions. 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]
Part 3 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.
Part 5 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 exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion. 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

SECTION VII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Not Applicable At This Time]

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). Various projects have been evaluated since the last Part 70 renewal permit was issued, but this modification does not in itself increase emissions, so no further analysis is necessary.

NSPS, 40 CFR Part 60 [Subparts D, Dc, GG, and OOO 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 were each rated at 4,775 MMBTUH, and were 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 currently by Unit 3 are as follows:

- 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 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 that demonstrated 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. 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 that exceeds 0.8% by weight sulfur shall be used, 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.
Subpart OOO (Nonmetallic Mineral Processing Plants) affects equipment at facilities that crush or grind nonmetallic minerals, including sodium compounds. The M-5 project includes an air classifier mill that grinds sodium bicarbonate, so the related equipment will be subject to the standards of the subpart. The material will be pneumatically transferred to a storage silo, after which the entire process, including the classifier mill, is enclosed. The silo filter will be subject to an opacity limit of 7%, but will be exempt from a stack concentration limit per 40 CFR 60.672(f). Compliance with the opacity standard shall be demonstrated by Reference Method 9 testing within 60 days of achieving maximum production, but no later than 180 days after first operation.
Subpart IIII (Stationary Compression Ignition Internal Combustion Engines {CI-ICE}) affects CI-ICE constructed, modified, or reconstructed after July 11, 2005. The emergency generators manufactured and went into operation prior to 2005, and are not affected facilities.

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 [Subparts ZZZZ and UUUUU Applicable]
Subpart Q (Industrial Process Cooling Towers) All facilities operated by this company ceased using chrome in cooling water three decades ago.
Subpart ZZZZ (Reciprocating Internal Combustion Engines or RICE). The two oil-fired emergency generators qualify as existing "emergency stationary RICE" per the definition found in 40 CFR 63.6675 and shall comply with this MACT per 40 CFR 63.6640(f).
Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters) affects boilers and heaters located at, or part of, major sources of HAPs. The boilers associated with coal-fired electric utility steam generating unit 3 is exempt from the subpart per 40 CFR 63.7491(c). All other boilers and process heaters are subject to the subpart. However, because all units except 3 were described as "Units designed to burn Gas 1 fuels," no emission limitations apply. Except for normal recordkeeping and notification requirements, only work practice standards apply, as found in Item 4 of Table 3. These include one-time energy assessments and a number of inspections, evaluations, reviews, and reports detailed in paragraphs a through h of Item 4. Compliance with all provisions is required no later than January 31, 2016.
Subpart UUUUU (Coal- and Oil-Fired Electric Utility Steam Generating Units) affects new, reconstructed, and existing electric generating units (EGUs) that combust coal or oil. Unit 3 at Northeast is subject to the subpart, which limits the MATS MACT, that is front-half PM less than or equal to 0.0300lbs/MMBTU, total PM less than or equal to 0.0380 lb/MMBTU, PM_{10} less than or equal to 0.019 lbs/MMBTU, and $PM_{2.5}$ less than or equal to 0.0144 lbs/MMBTU. Compliance with acid gas and mercury (or their surrogates) limits of the MACT shall also be required. EPA Reference Method testing shall be performed to show compliance with these limits. The current project is designed to assure compliance. Discussion of the project is found in the closing paragraphs of Section II, Facility Description, and the compliance requirements were included within the TVR (M-5) permit.
Subpart JJJJJJ (Industrial, Commercial and Institutional Boilers and Process Heaters) affects boilers and heaters located at, or part of, area sources of HAPs. The facility is a major source of HAP.
Subpart CCCCCC (Gasoline Dispensing Facilities) affects gasoline cargo truck deliveries and storage tanks that dispense to facility vehicles at area sources of HAP. Although the facility has a 2,000-gallon tank, the facility is major for HAP, and is not an affected facility under the subpart.

CAM, 40 CFR Part 64 [No longer 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

Emission units subject to an emission limit or standard proposed after November 15, 1990, pursuant to Section 111 or 112 of the Clean Air Act, are exempt from CAM. Unit 3 is subject to the PM standards of 40 CFR 63 Subpart UUUUU, which was proposed after 1990, and is exempt from CAM.

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 3, 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 II NO_X requirements) [Applicable]
NO_X emission limits are set in Permit No. 2009-470-ARR2 based on Phase II limits commencing January 1, 2008, under 40 CFR 76.8 for Unit 3. Compliance with the Acid Rain annual NO_X requirements will be according to the averaging plan.

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.

SECTION VIII. COMPLIANCE

Tier Classification And Public Review

This application has been classified as **Tier I** based on the request for a minor modification to a Part 70 operating permit. Public review is not required.

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 application involves only land owned by the applicant. 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/. This site is not within 50 miles of the Oklahoma border.

The permit was sent as "Proposed" to the EPA Region VI for a 45-day review. No comments were received from EPA Region VI.

Inspection

A full compliance operating inspection was conducted on May 13, 2013. The inspection was conducted by Rhonda Jeffries, Environmental Programs Manager from the DEQ Regional Office at Tulsa. No violations were reported, although clarification of some records was requested. 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, 1B, and 2 in July 2013, and for flow and CEMs at Units 3 and 4 in May 2013. The following tables include a demonstration of compliance with OAC 252:100-19, as well as with NSPS Subpart D, for Units 3 and 4.

Emissions (Lbs/MMBTU)				Opacity (%)		
Filterable	NSPS D	Total	Subch 19	COMS	VE	NSPS
Unit 3 June 14, 2006 (three run averages)						
0.0143	0.10	0.0379	0.132	6.0	6.9	20
Unit 4 May 11, 2006 (three run averages)						
0.0224	0.10	0.0591	0.132	11.0	11.6	20

Fee Paid

Minor modification to a Part 70 operating permit fee of $3,000.

SECTION IX. SUMMARY

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

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

MARY FALLIN
Governor

AUG 22 2016

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

Re: Permit Application No. **2012-918-TVR2 (M-1)**
PSO Northeastern Station (Facility ID: 212)
Section 4, T22N, R15E, Rogers County, Oklahoma

Dear Mr. Barton:

Enclosed is the permit authorizing operation of the referenced facility. 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 emissions inventory for this facility. An emissions 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 Emissions 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 (405) 702-4100.

Sincerely,

Phillip Fielder, P.E.
Permits & Engineering Group Manager
AIR QUALITY DIVISION

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. 2012-918-TVR2 (M-1)

American Electric Power,

having complied with the requirements of the law, is hereby granted permission to operate 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 June 21, 2016, and specific conditions, both attached.

This permit shall expire five (5) years from the date when Title V Renewal Operating Permit No. 2012-918-TVR2 was issued (11/18/2014), except as authorized under Section VIII of the Standard Conditions.

Permits & Engineering Group Manager

8/17/2016
Issuance Date

PERMIT TO OPERATE
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

American Electric Power
Public Service Company of Oklahoma
Northeastern Power Station

Permit Number 2012-918-TVR2 (M-1)

The permittee is authorized to operate in conformity with the specifications submitted to Air Quality on December 21, 2015, with additional information submitted on various later dates. The Evaluation Memorandum dated August 17, 2016, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and 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 original 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	1.18	5.19	
PM_{10} [2]	20.9	81.1	
VOC	0.40	1.49	
CO	51.7	198	12
H_2SO_4	0.06	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), or upon completion of combustion tuning after an outage, as required by the manufacturer. **Shutdown** begins when the turbine exits Mode 6 and ends with the termination of fuel flow to the turbine, or with recommencement of start-up. 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	1.26	5.50
PM_{10} *	21.9	85.5
VOC	0.50	1.92
CO	60.6	237
H_2SO_4	0.06	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 limit is 0.148 lbs/MMBTU for CO rolling 3-hour average. The new NO_X limit will be 0.28 lbs/MMBTU rolling 30-calendar day average. CO compliance shall be demonstrated by Reference Method testing once every four operating quarters, as defined in 40 CFR 75.

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, Aux 3, 6-9, and Coal Pile

EUG 3 Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const/Mod Date
3	3	Combustion Engineering #4974 SCRR	490	4775	Apr, 1974/June 2015

EUG Aux 3 Steam Generator

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

For Unit 3, the CO BACT emission limit is 0.530 lbs/MMBTU rolling 3-hour average, demonstrated by Reference Method testing once every four operating quarters, as defined in 40

CFR 75. The new NO_X limit will be 0.15 lbs/MMBTU rolling 30-calendar day average when firing 100% on coal. The current limits are shown in the following table.

Source	Pollutant	Lbs/MMBTU
Unit 3	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. As of April 16, 2016, Unit #3 has been subject to the limits of the MATS MACT, that is front-half PM less than or equal to 0.0300lbs/MMBTU, total PM less than or equal to 0.0380 lb/MMBTU, PM_{10} less than or equal to 0.019 lbs/MMBTU, and $PM_{2.5}$ less than or equal to 0.0144 lbs/MMBTU. Compliance with acid gas and mercury (or their surrogates) limits of the MACT shall also be required. EPA Reference Method testing shall be performed to show compliance with these limits.

EUG 6A & 6B **Rotary Car Dumper Baghouses (East and West)**

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

EUG 7 **Emergency Reclaim Water Curtain (Make: "Engart", July 2009)**

EU	Point	Make/Model	Const/Mod Date
7	7	Peabody #S1-5	Apr, 1974/July 2009

EUG 8 **Crusher House Water Curtain (Make: "Engart", July 2009)**

EU	Point	Make/Model	Const/Mod Date
8	8	Peabody #S2-9	Apr, 1974/July 2009

EUG 9 **Unit 3 Coal Silo (Cascade) Dust Collector**

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

EUG Coal Pile

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

EU	Point	Make/Model	Const Date
--	--	Coal Pile	Apr, 1974

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
$TSP = PM_{10}$	1.64	0.72
SO_2	0.13	0.06
NO_X	41.0	18.0
CO	18.1	7.94
VOC	1.19	0.52

E. **EUG 11 - 15** 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

EUG 14 Byproduct Handling Fugitives

EUG 15 Bin Vent Filters*

EU	Point	Source	Const Date
15	1	Sorbent silo 1	Feb. 2016
15	2	Sorbent silo 2	Feb. 2016
15	3	Activated carbon silo	Feb. 2016
15	4	Byproduct silo	Feb. 2016
15	5	Classifier mill 1	Feb. 2016
15	6	Classifier mill 2	Feb. 2016

**authorized under (M-5) and completed on Feb. 2016.*

These filters are process equipment designed to retain product, secondarily acting as pollution control devices.

EUG 16 Emergency Engines (for Emergency Generators)

EU	HP	Description	Fuel Type	Function	Mfg. Date
GEN 1/2	3,600	General Motors, Model MP45A	Diesel	for Units 1 & 2	05/1968
GEN 3	1,476	Detroit Diesel Allison, Model 16V-149T	Diesel	for Unit 3	02/1979

The engine shall be operated as follows.

a. The owner/operator shall comply with this NESHAP Subpart ZZZZ (40 CFR 63.6640(f)).
b. The engine shall be fueled with diesel with a maximum sulfur content of 0.0015% by weight.
c. The operating hours for each emergency engine shall be limited to 100 hours/year.

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. All limits in Specific Condition 1 apply to Unit 2 while operating 100% on natural gas, and to Unit 3 while operating 100% on coal. Auxboiler 3 operates under a 10% annual capacity factor. Unit 3 is 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 only for Unit 3.

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.). For the purposes of calculating and reporting NO_2 and SO_2 emissions, methods prescribed by 40 C.F.R. Part 75 shall be used. 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 192,720 MMBtu/yr (equivalent to a 10% annual capacity factor) for Auxboiler 1/2.

3. 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)]

4. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements as listed in renewal Permit No. 2014-1749-ARR3, 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, dated December 16, 2011, 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.

5. The boiler at Unit 3 is 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).

6. 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]

7. The permittee shall not replace the modified burners on Unit 2, the low-NO_X concentric firing systems of Unit 3, or the electrostatic precipitators on Unit 3 except by devices of equal or greater control efficiency. NO_X control efficiency of the modified burners is estimated to be 40%, and Unit 3 NO_X emissions are anticipated to be well below the acid rain requirements considering after installation of the low-NO_X concentric firing systems. The PM control efficiency of the ESPs is estimated to be 99.6%. By the extension date of April 16, 2016, the Unit 3 ESP started utilizing as a product recovery device only, not as a control device. The fabric filter will become the control device for Unit 3, with particulate matter emission rate expected to be 0.038 lbs/MMBTU, of which 0.030 is filterable and 0.008 is condensable. [OAC 252:100-43]

8. Compliance with Reference Method testing for Unit #3 due to the completion of the refined tuning project of 2003-410-C (M-6) shall be performed as described in 40 CFR 60.8. Results shall be used to determine appropriate indicators of compliance with the emissions limits of Specific Condition #1 for the unit. [OAC 252:100-43]

9. 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 Unit 3.
[Consent Order 06-316]

10. Performance testing to establish PM_{10} emissions from Unit 3 shall be performed at least once every second year. If testing for a particular unit is performed in 2014, future testing for that unit will occur in each succeeding even-numbered year. Similarly, if testing was performed in 2013 or will be performed in 2015, future testing for that unit will be performed in each succeeding odd-numbered year. 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 #9. [OAC 252:100-43; 40 CFR 64]

11. 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

12. Unit 3 is prospectively subject to NESHAP Subpart UUUUU and shall comply with all requirements of the subpart, including construction of the project, monitoring, reporting, and recordkeeping, no later than the extension date of April 16, 2016.

[40 CFR 63 Subpart UUUUU, 43 CFR 63.6(i)(4)(i)(A)]

(a) §63.9980 What is the purpose of this subpart?
(b) §63.9981 Am I subject to this subpart?
(c) §63.9982 What is the affected source of this subpart?
(d) §63.9983 Are any EGUs not subject to this subpart?
(e) §63.9984 When do I have to comply with this subpart?
(f) §63.9985 What is a new EGU?
(g) §63.9990 What are the subcategories of EGUs?
(h) §63.9991 What emission limitations, work practice standards, and operating limits must I meet?
(i) §63.10000 What are my general requirements for complying with this subpart?
(j) §63.10001 Affirmative defense for exceedance of emission limit during malfunction.
(k) §63.10005 What are my initial compliance requirements and by what date must I conduct them?
(l) §63.10006 When must I conduct subsequent performance tests or tune-ups?
(m) §63.10007 What methods and other procedures must I use for the performance tests?
(n) §63.10008 [Reserved]
(o) §63.10009 May I use emissions averaging to comply with this subpart?
(p) §63.10010 What are my monitoring, installation, operation, and maintenance requirements?
(q) §63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?
(r) §63.10020 How do I monitor and collect data to demonstrate continuous compliance?
(s) §63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?
(t) §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(u) §63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?
(v) §63.10030 What notifications must I submit and when?
(w) §63.10031 What reports must I submit and when?
(x) §63.10032 What records must I keep?
(y) §63.10033 In what form and how long must I keep my records?
(z) §63.10040 What parts of the General Provisions apply to me?
(aa) §63.10041 Who implements and enforces this subpart?
(bb) §63.10042 What definitions apply to this subpart?

13. All boilers and process heaters, with the exception of Units 2 and 3, are subject to NESHAP Subpart DDDDD, and shall comply with all requirements of the subpart no later than January 31, 2016. [40 CFR 63 Subpart DDDDD]

§ 63.7480, 7485, 7490, 7491, 7495	What This Subpart Covers
§ 63.7499, 7500, 7501	Emission Limitations and Work Practice Standards
§ 63.7505	General Compliance Requirements
§ 63.7510, 7515, 7520, 7521, 7522, 7525, 7530, 7533	Testing, Fuel Analyses, and Initial Compliance Requirements
§ 63.7535, 7540, 7541	Continuous Compliance Requirements
§ 63.7545, 7550, 7555, 7560	Notification, Reports, and Records
§ 63.7565, 7570, 7575	Other Requirements and Information
Tables 1 through 13	

14. The sodium bicarbonate transportation, storage, and grinding systems are subject to NSPS Subpart OOO. The systems shall comply with all applicable requirements.

[40 CFR 60, Subpart OOO]

§ 60.670	Applicability and designation of affected facility.
§ 60.671	Definitions.
§ 60.672	Standard for particulate matter (PM).
§ 60.673	Reconstruction.
§ 60.674	Monitoring of operations.
§ 60.675	Test methods and procedures.
§ 60.676	Reporting and recordkeeping.
Table 1	Exceptions to applicability of Subpart A.
Table 2	Stack emission limits
Table 3	Fugitive emission limits

15. 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 #7.
f. Maintenance and visual inspection of particulate filter systems (weekly).
g. Pressure drop or manufacturer's recommendation for the Unit 3 fabric filter.
h. Hours each CT spends in start-up and in shutdown, as required by Specific Condition #1 (A) EUG 1.
i. Data demonstrating compliance with NSPS Subpart GG, as required by Specific Condition #11.
j. Records required by NESHAP Subpart UUUUU, per SC #12.
k. Records required by NESHAP Subpart DDDDD, per SC #13.
l. Records required by NSPS Subpart OOO, per SC #14.
m. Records required by NSPS Subpart D, per SC #5.
n. Operating hours of each emergency generator (monthly and 12-month rolling total).

16. 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 the ash management contractor.
f. Records for any other activity, demonstrating that emissions are less than 5 TPY.
g. Vapor pressure of the drip in the Unit 1 and Unit 2 Gas Yard's Condensate Drip Tank.

17. The boilers in EUG 2 and 3 are subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and shall comply with all applicable requirements including, but not limited to, the following. [40 CFR §§ 51.300-309 & Part 51, Appendix Y]

a. The following sources are affected facilities and are subject to the requirements of this Specific Condition, the Protection of Visibility and Regional Haze Requirements of 40 CFR Part 51, and all applicable SIP requirements.

EU ID#	Point ID#	EU Name	Heat Capacity (MMBTUH)	Construction Date
2	2	Babcock and Wilcox UP-60	4754	1970
3	3	Combustion Engineering #4974 SCRR	4775	1974

b. Each existing affected facility shall install and operate the SIP-approved BART as expeditiously as practicable but no later than April 16, 2016 for Unit 3.

c. The affected facilities shall be equipped with the following current combustion control technology, as determined in the submitted BART analysis, to reduce emissions of NO_X to below the emission limits listed in (f) below.
   i. New Low-NO_X Burners
   ii. Overfire Air
d. The permittee shall maintain the Low-NO_X burners, overfire air and ESP (or primary particulate matter control device), and shall establish procedures to ensure the controls are properly operated and maintained.
e. Within 60 days of achieving maximum power output from each affected facility after modification or installation of BART, but not to exceed 180 days from initial start-up of the affected facility, the permittee shall be in compliance with the emission limits established in the construction permit. The emission limits established in the construction permit shall be consistent with manufacturer's data and an agreed-upon safety factor. The emission limits established in the construction permit shall not exceed the following emission limits.

EU ID#	Point ID#	NO_X	Averaging Period
2	2	0.28 lb/MMBtu	30-day rolling

EU ID#	Point ID#	NO_X[1] Emission Limit	Averaging Period
3	3	0.15 lb/MMBtu	30-day rolling

[1]Limits apply only when units are firing 100% on coal.

EU ID#	Point ID#	PM_{10}[1] Emission Limit	Averaging Period	Combined Annual Emission Rate
3	3	0.10 lb/MMBtu	3-hour rolling	4,183 TPY 12-month rolling

[1]Current emissions limits for ESPs are based on minimum NSPS requirements for front half catch. As part of the permitting process, PSO will be required to propose emission limits for front and back half reflective of the control technology and consistent with performance test results.

f. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da.
g. Upon completion of the BART project, but no later than April 16, 2016, Unit 3 (nominally) shall be in compliance with 30-day rolling average SO_2 limits of 0.4 lb/MMBTU and 1,910 lb/hr, and with an annual SO_2 emission rate of 8,366 tons. The limits on SO_2 include 0.65 lb/MMBTU (3,104 lb/hr) 30-day rolling average for Unit 3 no later than January 31, 2014. Additionally, a 0.60 lb/MMBTU 12-month rolling average for each of Unit 3, as well as 25,097 TPY (12-month rolling) for the combined Units 3 and 4 no later than December 31, 2014.
h. Within 60 days of achieving maximum power output from each boiler, after modification of the boilers, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing and furnish a written report to Air Quality. Such report shall document compliance with BART emission limits for the affected facilities.

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

18. No later than 30 days after each anniversary date of the issuance of the original Title V permit (June 30, 1999), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, certification of compliance with the terms and conditions of this permit. [OAC 252:100-8-6 (c)(5)(A) & (D)]

19. This permit supersedes all previous Air Quality operating permits for this facility with the exception of Acid Rain Renewal Permit No. 2014-1749-ARR3.

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(June 21, 2016)

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(17) 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]