OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **December 9, 2019**

TO: Phillip Fielder, P.E., Chief Engineer

THROUGH: Eric L. Milligan, P.E., Manager, Engineering Section

THROUGH: David Schutz, P.E., New Source Permits Section

FROM: Amalia Talty, P.E., New Source Permits Section

SUBJECT: Evaluation of Permit Application No. **2014-1309-C (M-2) (PSD)**
Kiowa Power Partners, LLC
Tenaska Kiamichi Generating Station
Facility ID: 4258
Section 34, Township 3N, Range 13E, Pittsburg County, Oklahoma
Latitude: 34.68363°N, Longitude: 95.93490°W
Direction: From the junction of Highways 69/63 in Kiowa, 3.7 miles S/SW on HW 69 to the first road west of the railroad tracks, turn W/NW (right) at 34.67750°/-95.93419, continue W/NW and N for a total of 0.25 miles to facility gate.

SECTION I. INTRODUCTION

Kiowa Power Partners, LLC (KPP or applicant) submitted an application to reopen and modify their Prevention of Significant Deterioration (PSD) Construction Permit [Permit No. 2000-103-C (M-1) (PSD)] issued on May 1, 2001, for their Tenaska Kiamichi Generating Station. The purpose of this modification is to establish alternate emission limits for two (2) additional operating scenarios, grid swaps and black start tests, during which the steady-state emissions limitations in Specific Condition 1 cannot be met and for which the alternate limits in Specific Condition 1.b will apply.

<u>Grid Swaps</u>

Kiamichi is a duel-grid plant, having the ability to send energy to either the Electric Reliability Corporation of Texas (ERCOT) or Southwest Power Pool (SPP) system. Kiamichi's power off-taker (customer) has requested the plant to have the ability to perform on-line grid swaps, which means changing the grid onto which energy is sent without shutting the combustion turbines down the re-starting on the other grid. In order to do this safely and without mechanical stress on the turbines, load is reduced below that which is needed to maintain compliance with the stead-state emission limits, the switchgear breakers are opened on the current grid and closed on the other grid, and turbine load increased to the dispatched rate.

<u>Black Start Testing</u>

KPP off-taker has intentions to bid the plant into SPP and/or ERCOT as a "black start resource" meaning it will be relied upon to start without back-feed grid power in the event of a grid outage and feed power onto the grid to re-establish a stable, functioning system. As a black start resource, KPP will need to periodically perform black start tests to demonstrate to the grid system operator(s) that it maintains the ability to satisfactory perform in case of a grid emergency. While the duration and other specifics of an actual grid emergency cannot be predicted or quantified, the testing events have defined parameters upon which emission estimates can be based. These test events will require KPP to start up using back-feed power from one grid and then, operating one or more combustion turbines, energize the transmission line on the other grid while operating at low loads in order to slowly begin to feed power onto that system.

As described above, both scenarios require the combustion turbines to operate for a period of time at loads below which are required to maintain compliance with the steady-state NO_x concentration limitations (nominally 50% of base load), similar to start-up and shutdown events. These elevated concentrations can be high enough to cause the 3-hour rolling average to exceed permit limits. Further, due to the higher concentrations, the hourly mass emission rates also increase despite the lower mass exhaust flow. It is possible the higher hourly mass emission rates will also cause the 3-hour rolling average to exceed the permit limit. However, the allowable NO_X emission rate in OAC 252:100-33-2(a)(1) of 0.20 lb/MMBTU (3-hr rolling average) should not be exceeded.

Specific Condition 1.ii of the current Title V permit [2014-1309-TVR2] contains alternate NO_x emission limits during periods of startup (802 lbs/event) and shutdown (217 lbs/event) in recognition of higher emissions during these events. Grid swaps and black start tests do not fit neatly within the definition of these events as the units are not completely shut down (in the case of grid swaps) and do not follow the typical startup procedure and ramp rates. Therefore, KPP is requesting the existing alternate emission limit for startup to cover both additional operating scenarios. Emissions during grid swaps and black swap tests will not exceed that allowed for startups (i.e., 802 lbs/event) and the durations will be less that that allowed for startups (i.e., 4 hours). Therefore, KPP requests that grid swaps and black start tests simply be added to the operating scenarios for which the alternate NO_X emission limit applies. As with the establishment of the alternate startup/shutdown limits in 2009, no increase in allowable annual emissions is being requested.

SECTION II. FACILITY DESCRIPTION

The facility includes four (4) 181.6 MW natural gas-fired combustion turbines (GE PF7241FA or equivalent) with four (4) 650-MMBTUH duct burners operating in combined-cycle mode with four heat recovery steam generators (HRSGs) and two to four steam turbines. In addition, the facility includes two (2) cooling towers, a fuel system, one (1) diesel fire-water pump engine, and a diesel storage tank.

Two gas turbines are paired with one steam turbine, powered by steam produced in two HRSG's from the two gas turbines' exhaust gas. The exhaust gas from each turbine may be further heated by duct burners (located in the HRSG) to provide additional steam. A natural gas-fired auxiliary boiler was intended to provide heat to facilitate start-up for all turbines by pre-heating the steam turbine. However, as noted in the July 12, 2010 Permit Memorandum, it was not installed and is not included as a permitted equipment item. If, at some time in the future, the auxiliary boiler mentioned above is installed it will require a construction permit.

The turbines use dry low-NO_X combustors. There are no add-on controls. A typical dry low-NO_X burner for a turbine consists of one diffusion flame pilot nozzle surrounded by several equally spaced premix flame main nozzles. A typical dry low-NO_x burner for a turbine consists of one diffusion flame pilot nozzle surrounded by several equally spaced premix flame main nozzles. The formation of NO_x is influenced by how much gas is burned in the pilot flame and how much is burned in the surrounding combustor nozzles. The multi-nozzle design spreads the combustion volume into a wider, cooler, less concentrated flame. Typically, for natural gas fuel, approximately 7 to 10 % by volume of the total gas flow is sent through the pilot nozzle. Other than startup, shutdown, and malfunctions, each combustion turbine will be operated at sufficient turbine load to assure operations in the "pre-mix" mode. Pre-mix is the operating mode for the burner which optimizes combustion efficiency and produces the lowest NO_x emissions. However, elevated levels of NO_x and CO can result during cold startups and/or in the "diffusion" mode. These turbines are designed to operate in the pre-mix mode almost immediately after light-off.

The duct burners fire only natural gas at a maximum heat input rate of 650 MMBTUH for each unit. There are four 19-foot diameter stacks venting the combustion turbines and HRSG exhausts at 165' above grade. Limits on operating hours of 8,760 hours per year for the turbine engines and 6,907 hours for the duct burners are carried forward from previous permits.

The fire pump is rated at 360-hp (0.32-MMBTUH) and includes an associated 572-gallon diesel fuel storage tank. The storage tank is an insignificant source for purposes of this permit.

Waste heat at the facility is handled by two cooling towers. Each of the cooling towers has ten cells. They are mechanical draft, counter-flow type with an associated liquid drift. Drift particulate emissions are caused by dissolved and suspended solids contained within the liquid droplets. The water droplets evaporate, allowing particulates to agglomerate. The cooling towers are permitted to operate continuously (8,760 hours per year). These emission units cannot be considered trivial activities pursuant to Appendix J of OAC 252:100 because they have BACT limits.

SECTION III. EQUIPMENT

EU ID#	Point ID#	EU Name/Model	Construction Date
1	Block 1, Unit 101	Combustion Turbine, GE PG7241FA, w/duct burner	11/24/2002
	Block 1, Unit 201	Combustion Turbine, GE PG7241FA, w/duct burner	12/08/2002
	Block 2, Unit 101	Combustion Turbine, GE PG7241FA, w/duct burner	01/11/2003
	Block 2, Unit 201	Combustion Turbine, GE PG7241FA, w/duct burner	01/24/2003
3	Fire Pump	360-hp, Diesel Fire Pump	July 2002

SECTION IV. EMISSIONS

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

A. Criteria Air Pollutants

The following table shows emissions based on best available data. Emission factors for the turbines for NO_X, SO_2, PM_{10}, VOC, and CO are based on manufacturer's guarantees for the model PG7241FA, based on 14 °F ambient, Base Load, and 8,760 hours per year. Emissions of SO_2 are based on 2 grains of sulfur per 100 SCF gas fuel. Emissions of lead are estimated using the emission factor given in AP-42 (7/98) Tables 1.4-2. This is applicable to the duct burners only; Table 3.1-2a (turbines) does not have a factor for gas-fired turbines. The heating value of natural gas is taken to be 1,012 BTU/SCF.

Emissions per Unit

Pollutant	Emission	Gas Turbine		Factor	Duct Burner	
	Factor ppmvd @15% O_2	lb/hr	TPY	lb/MMBTU	lb/hr	TPY
NO_x	9.0	63	275.94	0.080	52	179.58
SO_2		10.6	46.43	0.00154	3.67	12.66
PM_{10}[1]		13.06	57.19	0.010	7.34	25.36
VOC	1.4	3.0	13.14	0.050[2]	22.75	78.57
CO	9.0	31	135.78	0.060	39	134.69
Lead	Negligible	0.028	0.121	0.0000005	0.0003	0.0012

[1]Also includes acid mist

[2]0.020 lb/MMBTU @100% load, 0.050 lb/MMBTU @70% load

Pollutant	Four (4) Turbines (Total)		Four (4) Duct Burners (Total)		Four (4) Units Total	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY[1]
NO_X	252.0	1,103.76	208.0	718.32	460.0	1,822.08
SO_2	42.40	185.72	14.68	50.64	57.08	236.36
PM_{10}[2]	52.24	228.76	29.36	101.44	81.60	330.20
VOC	12.0	52.56	91.0	314.28	103.0	366.84
CO	124.0	543.12	156.0	538.76	280.0	1,081.88
Lead	0.112	0.484	0.0012	0.0048	0.113	0.489

[1] Based on 8,760 hours for the turbines and 6,907 hours of operation for the duct burners.
[2] Also includes acid mist.

Emissions from the diesel fire pump are calculated using manufacturer's data. The 360-hp diesel fire pump is rated at 0.32-MMBTUH. Emissions for the fire pump is calculated using 500 operating hours per year. Emissions from the associated 572-gallon diesel storage tank are negligible.

Pollutant	Emissions (lb/hr)	Emission total (TPY)
NO_X	8.37	2.09
CO	1.80	0.45
SO_2	0.22	0.06
VOC	0.68	0.17
TSP=PM_{10}	0.59	0.15
Lead	Neg.	Neg.

[1]based on a maximum sulfur content of 0.5% sulfur
[2]No data available

Emissions from the cooling tower were calculated for the original BACT limits using data method from AP 42, Fifth Edition, Volume I, Chapter 13: Miscellaneous Sources, 13.4 Wet Cooling Towers (Rev. 1/95) assuming a drift ratio of 0.001% and total dissolved solids (TDS) of 8,000 ppm. Combining two towers of twelve cells each yields 14.1 lb/hr or 61.76 TPY of TSP. There are currently ten cells in each tower.

Total Facility Criteria Pollutant Emissions

Equipment	NO_X		CO		VOC		SO_2		PM_{10}		Lead	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Turbine (4)	252.0	1103.76	124.0	543.12	12.0	52.56	42.40	185.72	52.24	228.76	0.112	0.484
Duct Burner (4)	208.0	718.32	156.0	538.76	91.0	314.28	14.68	50.64	29.36	101.44	0.0012	0.0048
Fire Pump	8.37	2.09	1.80	0.45	0.68	0.17	0.22	0.06	0.59	0.15	Neg.	Neg.
Cooling Tower	--	--	--	--	--	--	--	--	14.1	61.76	0.00	0.00
Total[1]	**460.0**	**1824.17**	**280.00**	**1,082.3**	**103.00**	**367.01**	**57.08**	**236.42**	**96.29**	**392.11**	**0.1132**	**0.489**

[1]Note: lb/hr totals do not include fire pump.

An emissions factor for sulfuric acid was developed using the rationale found in AP-42 (9/98), Section 1.3.3.2. Although this section of AP-42 deals with liquid fuels, the discussion makes clear that the formation of acid mist is a function of SO_2 availability and is not a function of burner design or fuel. An emissions estimate was developed based on information from the manufacturer showing that 10% (by weight) of the total SO_2 produced from the combustion turbines is converted to SO_3 (on a one-to-one mole basis) by the combustion turbines (based on the LHV). In addition, 15% of the total SO_2 produced from the combustion turbines and 15% of the total SO_2 produced by the duct burners is converted to SO_3 by the duct burners (based on the HHV). Finally, all of the SO_3 is then converted to H_2SO_4 (on a one-to-one mole basis).

Emissions Unit	SO_2 Emissions lb/hr	SO_3 Emissions	H_2SO_4 Emissions (each unit) lb/hr	H_2SO_4 Emissions (each unit) TPY[1]	H_2SO_4 Emissions (4 units) lb/hr	H_2SO_4 Emissions (4 units) TPY[1]
Turbine	10.59	1.323[2] +1.986[3]	4.053	17.751	16.212	71.002
Duct Burner	3.67	0.689[4]	0.843	2.910	3.371	11.641
Facility Total:					**19.584**	**82.643**

[1]Based on 8,760 hours for the turbines and 6,907 hours of operation for the duct burners.
[2] 10% of the total SO_2 from the combustion turbine is converted to SO_3 by the turbine
[3] 15% of the total SO_2 from the combustion turbine is converted to SO_3 by the duct burner
[4] 15% of the total SO_2 from the duct burner is converted to SO_3 by the duct burner

An estimate was not made for diesel fuel since low-sulfur fuel is used and these emissions sources only operate 500 hrs/year. Thus, emissions of H_2SO_4 are expected to be negligible.

$PM_{2.5}$ Emissions

The applicant submitted the following estimate of $PM_{2.5}$ emissions. $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions for combustion sources.

Equipment	$PM_{2.5}$	
	lb/hr	TPY
Turbine (4)	52.24	228.76
Duct Burner (4)	29.36	101.44
Fire Pump	0.59	0.15
Cooling Tower	0.02	0.08
Total	**82.21**	**330.43**

B. Hazardous Air Pollutants (HAPs)

HAP emissions are shown in the table on the next page and are based on AP-42 (4/00), Table 3.1-3 for the turbines, and AP-42 (7/98), Table 1.4-3 and Table 1.4-4 for other natural gas fired equipment. Estimates shown in the table for each emissions unit represent the total emissions (both lb/hr and TPY) from all such units.

The table on page 7 is a rework of the HAP/TAC table presented in the original PSD permit with the TAC pollutants deleted as they are not a concern at this time. Certain emissions factors were replaced with California Air Toxics Emissions Factors. These are identified with Footnote No. 1. In calculating the annual emissions for the Duct Burners, the applicant increased the operating hours from 6,907 to 8,760. The permit limit remains at 6,907 hours. HAP emissions based on a higher heating value for natural gas fuel of 1,012 Btu/scf. Emissions calculations resulting in values that round to zero at two decimal places, such as Benzo(a)pyrene, were deleted.

Emissions Unit				**Combustion Turbines (Total)**		**Duct Burners (Total)**		**Diesel Fire Pump**		
Annual Operating (hours)				8760		6907		500		
Fuel Type				Natural Gas		Natural Gas		Diesel		
Heat Input (HHV) MMBTUH				1879		650		0.28		
Number of Units				4		4		1		
Pollutants	**Nat. Gas Emission Factor**	**CT Emission Factor**	**Diesel Engine Emission Factor**	**Emissions**		**Emissions**		**Emissions**		**Facility Total HAP Emissions**
	lb/MMBtu	**lb/MMBtu**	**lb/MMBtu**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**TPY**
Acetaldehyde	1.3538E-04 (1)	1.5415E-05 (1)	7.67E-04	1.018	4.457	0.040	0.176	0.000	0.000	4.63
Acrolein	6.40E-06	1.8182E-05 (1)	9.25E-05	0.048	0.211	0.047	0.207	0.000	0.000	0.42
Benzene	1.3142E-05 (1)	3.8142E-06 (1)		0.099	0.433	0.010	0.043	0.000	0.000	0.48
Ethylbenzene	1.76E-05 (1)	NA		0.133	0.582	0.000	0.000	0.000	0.000	0.58
Formaldehyde	9.0474E-05 (1)	2.915E-05 (1)		0.680	2.978	0.076	0.332	0.000	0.000	3.32
Hexane	2.5593E-04 (1)	Neg.(2)		1.924	8.425	4.625	0.000	0.000	0.000	8.64
Naphthalene	1.6403E-06 (1)	6.0277E-07		0.012	0.054	0.002	0.006	0.000	0.000	0.06
Propylene Oxide	4.78E-05 (1)	0	2.58E-03	0.355	1.555	0.000	0.000	0.000	0.000	1.56
Toluene	7.0158E-05 (1)	1.1858-05 (1)	4.08E-04	0.527	2.310	0.031	0.135	0.000	0.000	2.45
Xylene	2.5791E-05 (1)	2.7273E-05 (1)	2.85E-04	0.194	0.849	0.071	0.311	0.000	0.000	1.16
Totals:				4.99	21.85	4.90	1.21	0.00	0.00	23.3

(1) California Air Toxics Emissions Factors.

(2) If the value of 1.7787E-03 from the existing permit were used, the annual hexane emissions from the duct burners would be 20.26 TPY, making the facility total hexane emissions 28.89 TPY. For this permit, the applicant submitted copies of test results indicating that the highest VOC emissions occurrence was 0.3 lbs/hr from Block 2/Unit 201 with the duct burner operating at 70% and the turbine engine operating at 100% load, and VOC emissions from the same unit with only the turbine engine operating at 100% load were 0.6 lbs/hr. Therefore, assuming this factor is good for all four engines operating simultaneously, then the highest annual VOC emissions would be 10.51 TPY of which only a small portion would likely be hexane. Therefore the assumption that hexane emissions are negligible appears reasonable.

SECTION V. PSD REVIEW

PSD Review for Grid Swaps and Black Start Tests

Because the current permit limit for NO_X is based on a BACT limit (lbs/hr), the applicant was required to address the applicable aspects of PSD review for the requested grid swaps and black starts. The applicant has completed BACT and Impact analyses, resulting in a conclusion that no controls are technically feasible or cost effective. Modeling for NAAQS ambient impacts analyses was not included as part of the PSD review because there is no increase in annual emissions. PSD review for the original construction permit can be found in Permit No. 2000-103-C (M-1) (PSD). PSD review for startup and shut down can be found in Permit No. 2014-1309-TVR2.

Best Available Control Technology (BACT) Analysis

1. Identify Control Technologies

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable and consistent with the proposed project. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step.

In the combustion processes, NO_X is formed by two fundamentally different mechanisms: fuel NO_X and thermal NO_X. NO_X formation from natural gas combustion is primarily thermal NO_X.

"Fuel NO_X" forms when fuels containing nitrogen are combusted, which breaks the nitrogen bonds and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel. Therefore, since natural gas contains little or no fuel-bound nitrogen, fuel NO_X is not a major contributor to NO_X emissions from natural gas-fired combustion turbines.

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and react to form NO_X. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NH are oxidized to form NO_X. In addition to prompt NO_X, thermal NO_X is formed through the Zeldovich mechanism. The amount of NO_X generated through this mechanism increases exponentially as a function of temperature and linearly as a function of residence time. The rate of NO_X generation decreases significantly at temperatures below 2,780 °F. Therefore, reducing combustion temperature is a common approach to reducing NO_X emissions.

In lean premix systems, atmospheric nitrogen acts as a diluent, as fuel is mixed with air upstream of the combustor at fuel-lean conditions. The fuel-to-air ratio is maintained well below the ideal stoichiometric level to limit NO_X formation, as lean conditions cannot produce the high temperatures that create thermal NO_X. In addition, premixing prevents local "hot spots" within the combustor that can lead to significant NO_X formation. In stationary source combustion, little of the NO is converted to NO_2 in the combustion process. However, the NO continues to oxidize in the atmosphere.

NO_X reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce inerts (e.g., combustion products) that limit initial NO_X formation, or both. Post-combustion NO_X control technologies employ various strategies to chemically reduce NO_X to elemental nitrogen (N_2) with or without the use of a catalyst.

As was determined when the alternate startup and shutdown emission limits were established, add-on control technology such as selective catalytic reduction (SCR) is an available and demonstrated control technology during steady state operation. During on-line grid swaps, the combustion turbine(s) will already be operating in emissions compliance mode (6Q) before dropping load to below that needed to maintain compliance. SCR could potentially be effective in reducing emissions as the exhaust and catalyst temperatures could be sufficient to maintain the chemical reaction.

2. Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it has been demonstrated in practice. If so it is feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination. Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility. This step should be straightforward for control technologies that are demonstrated-if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated, and it is technically feasible."

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available." Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source.

Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: “An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.” Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual:

> *Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.*
>
> *For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.*

During black start testing, the combustion turbine(s) will be started and kept at low loads, similar to a portion of the startup sequence, while the transmission line is slowly energized. Unlike a startup, the combustion turbine(s) will not increase load to above the minimum emissions compliance level but will instead shut down when each test is concluded (unless the unit has been dispatched and it makes sense to increase load to the dispatched rate after the last test in lieu of shutting it down and re-starting).

As previously stated, add-on control technology such as SCR is an available and demonstrated control technology during steady state operation. However, it requires a gas stream at reaction temperatures between 600°F and 750°F, which is not available during startup and, thus similarly, black start tests. Therefore, SCR is not capable of controlling emissions during these tests and is considered technically infeasible.

3. Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review.

4. Evaluate Most Effective Controls and Document Results

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified.

Since installation of SCR is technically feasible for grid swaps, KPP conducted a detailed economic analysis to determine the cost to retrofit the existing combustion turbines with SCR and calculated the incremental reduction in NO_X emissions. The cost analysis includes capital costs associated with structural changes to the existing units, including HRSG duct modifications as well as installation of new equipment for ammonia storage, loading, and unloading, and the catalyst system. The cost analysis also includes direct costs associated with the operation and maintenance of the SCR system, cost of ammonia and catalyst, electricity consumption, and indirect costs such as overhead and administrative costs applied to the incremental NO_X emissions. Due to the number of expected grid swaps and their relatively short duration, SCR would not be cost effective. The cost is calculated as $60,200/ton of NO_X removed. Therefore, the installation of SCR as BACT is economically infeasible.

Economic Analysis for SCR for NO_X Control

Capital Cost Summary	
Total Capital Investment (TCI)[a]	$11,092,000
Annual Cost Summary	
Direct Annual Costs	
Operation and Maintenanc[e]	
Maintenance (1.5% of TCI)	$166,380
Reagent [c,i]	
Requirement (25 lb/hr/unit at $433 per ton) [d,i]	$7,422
Catalyst	
Catalyst Replacement [e,i]	$3,595,429
Catalyst Life (years)	20
Annual Interest Rate (%) [f]	7%
Future Worth Factor	0.024
Total Annual Catalyst Replacement Cost	$87,703
Utilities [g,i]	
Electricity (1,500 kWh at $0.041 per kW-hr)	$85,181
Total Direct Annual Costs (DAC)	**$346,706**
Indirect Operating Costs [b]	
Overhead (60% of O&M Costs)	$99,828
Administrative Charges (2% of TCI)	$221,840
Property Taxes (1% of TCI)	$110,920

Insurance (1% of TCI)	$110,920
Capital Recovery (CRF x TCI) 20 yrs @ 7% interest [h]	$1,047,006
Total Indirect Annual Costs (IAC)	**$1,590,514**
Total Annualized Cost (TAC = DAC + IAC)	**$1,937,221**
Cost Effectiveness Summary	
Annual Control Cost ($)	$1,937,221
Pollutant to be removed, NO_X (TPY) [i]	32.18
Control Cost Effectiveness ($/ton)	$60,201

[a] - Total Capital Investment includes purchased equipment costs, engineering, general facilities, project contingency, and other preproduction costs, +/- 20% based upon lower of two quotes received in Jan 2018 for similar (3-unit) facilities.

[b] - EPA CCM, Section 4.2, Chapter 2, "Selective Catalytic Reduction (SCR)," Sixth Edition, January 2018

[c] - Annual reagent cost calculated based on maximum estimated number of grid swaps multiplied by hourly reagent usage and cost.

[d] - Reagent usage rate and cost based on information from a similar facility and maximum estimated number of annual grid swap hours.

[e] - Catalyst replacement cost based on actual cost (in 2011) from a 3-unit facility scaled to 4 units and 2019 monies.

[f] - Interest rate conservatively set at 7%, based on EPA's seven percent social interest rate from OAQPS CCM Sixth edition.

[g] - Power consumption estimated from a similar 3-unit facility scaled to 4 units. Cost based on projected maximum annual grid swap hours. Electricity price based on the average industrial electricity rate in Mt. Enterprise, Rusk County, Texas in 2017, available at http://www.electrictylocal.com/states/oklahoma/kiowa.

[h] – Capital recovery factor calculated based on the EPA CCM, Chapter 2, "Cost Estimation: Concepts and Methodology," Section 2.4.4.4 "Equivalent Uniform Annual Cash Flow and Annualization", Equation 2.8a, Sixth Edition, January 2002. (CRH = 0.0944)

[i] – Reagent cost, catalyst replacement cost, and utilities cost associated with the increase in emissions is calculated based on the cost of controlling the total projected project actual NO_X emissions.

SCR was deemed technically infeasible for black start tests in Step 2 due to insufficient exhaust temperatures. An auxiliary boiler could potentially be used to warm the catalyst prior to startup. However, given SCR is not cost effective for grid swaps, it follows that SCR plus an auxiliary boiler for black start tests would also not be cost effective.

5. Select BACT

In the final step, the BACT emission limit is determined based on evaluations from the previous steps. Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard is infeasible, in which case a work practice or operating standard can be imposed.

The minimum control efficiency to be considered in a BACT assessment must result in an emission rate less than or equal to any applicable NSPS or NESHAP emission rate for the source.

As is the case with startup and shutdown, there are no such applicable emission limits for grid swaps or black start testing events.

Based on the BACT assessment, BACT for grid swaps and black start tests is the existing 802 lbs/event alternate emission limit and 4-hour duration limit established for startups. Compliance with the proposed BACT limit will be achieved via the existing Dry Low-NOX burners and good combustion practices. It should be emphasized that, as with startups, KPP is incentivized to minimize the duration of these events.

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 listed in OAC 252:100, Appendix Q. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards.

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

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

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAP 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 operating permit application, or are developed from the applicable requirement.

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

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
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 mitigation, 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 (Prohibition of Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
Section 19-4 regulates emissions of PM from the combustion of fuel in any new and existing fuel-burning unit, with emission limits based on maximum design heat input rating. Fuel-burning unit 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 turbines, duct burners, diesel fire pump are all subject to the requirements of this subchapter. As shown in the following table, all units are in compliance with this requirement.

Equipment	Maximum Heat Input (MMBTUH, HHV)	Allowable Particulate Emission Rate (lb/MMBTU)	Calculated Particulate Emission Rate (lb/MMBTU)	Stack Test Results (lb/MMBTU)
Turbines	1,879	0.17	0.010	0.007 (1)
Duct Burner	650	0.22	0.011	0.028 (1)
Diesel Fire Pump	0.28	0.6	0.32	N/A

(1) – The highest values of all four turbine and turbine with duct burner combinations were used.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The turbines and duct burners (electric utility steam generating unit) are not subject to Subchapter 25 since they are subject to an opacity limitation of NSPS Subpart Da and GG. The diesel fire pump is also subject to this subchapter. These units will assure compliance with this regulation by ensuring "complete combustion".
Continuous monitoring of opacity (COM) is required for fossil fuel-fired steam generators in accordance with 40 CFR Part 51, Appendix P and any fuel-burning equipment with a design heat input value of 250 MMBTUH or more, that does not burn gaseous fuel exclusively, and that was not in being on or before July 1, 1972, or that is modified after July 1, 1972. 40 CFR Part 51, Appendix P exempts fossil fuel-fired steam generators from the COM requirements when gaseous fuel is the only fuel burned. Since the combustion turbine and duct burner will only burn natural gas they are exempt from the opacity monitoring requirements.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. Under normal operating conditions, this facility has negligible potential to violate this requirement; therefore, it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input. Burning only natural gas with a maximum of 2 grains of sulfur per 100 SCF (0.0056 lb/MMBTU) will assure compliance for the turbines and duct burners. The diesel fire pump will fire diesel fuel and have maximum sulfur compound emissions of 0.29 lbs/MMBTU, which is well below the allowable emission limitation of 0.8 lb/MMBTU for liquid fuels.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.20 lbs of NO_X per MMBTU, three-hour average. The turbines and duct burners are equipped with DLN technology such that emissions will be well

below this standard during normal operation. Section 33-2(b) provides that if fuel-burning equipment, due to technological limitations, cannot meet the requirements of OAC 252:100-33-2(a) during startup and/or shutdown, the fuel-burning equipment shall comply with BACT for startup and/or shutdown as contained in a currently applicable Air Quality Division permit. Further, the NO_X emissions during startup and/or shutdown of this equipment shall not cause or contribute to an exceedance of any NAAQS or PSD increment and approval of technological limitations by the Director in an Air Quality Division permit does not mean automatic approval by the EPA. BACT for startup and shutdown (SUSD) was determined to be minimizing the duration of SUSD events and compliance with pound per SUSD event limits. The diesel fired pump is below 50 MMBTUH heat input and are, therefore, not subject to this regulation.

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

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates 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. Section III, Emissions, of the Title V permit identified a concern with seven TACs (acetaldehyde, formaldehyde, hexane, pentane, propylene oxide, sulfuric acid, and toluene) exceed their respective Category *de minimis* thresholds at the time that permit was issued. It was concluded that BACT for VOCs as addressed in Section IV.A of that permit would constitute BACT for the organic TACs. To summarize, there were no specific controls for HAP emissions in use on existing combustion turbines. A BACT and a case-by-case MACT determination were proposed utilizing best combustion practices and combustion control procedures, including DLN combustors and their inherent efficient fuel combustion. BACT for H_2SO_4 was also addressed in Section IV.A of that permit. For the Combustion Turbines and Duct Burners, the use of natural gas with a sulfur content of 2 grains/100 SCF was determined to be acceptable as BACT. For the diesel fire pump, good design and the use of low sulfur diesel fuel with a sulfur content not exceeding 05% by weight was determined to be acceptable as BACT. Likewise, compliance with the MAAC was demonstrated. Although no AOC has been designated that would merit

specific requirements for this facility at this time, there are no controls or limitations that would not otherwise be imposed that warrant removal or relaxation 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:

Rule	Category	Reason for Non-Applicability
OAC 252:100-7	Permits for Minor Facilities	not in source category
OAC 252:100-11	Alternative Reduction	not eligible
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Feed & Grain Facility	not in source category
OAC 252:100-39	Nonattainment Areas	not in a subject area
OAC 252:100-47	Landfills	not type of source category

SECTION VII. FEDERAL REGULATIONS

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

NSPS, 40 CFR Part 60 [Subparts Da and GG are Applicable]
<u>Subpart Da</u> (Electric Steam Generating Units) affects units with a design capacity greater than 250 MMBTUH constructed after September 18, 1978. Combined cycle gas turbines with such capacity are affected sources only if fuel combustion in the heat recovery unit exceeds the 250 MMBTUH level. Since 650 MMBTUH is added by duct burners in the HRSGs, the duct burners

are subject to Subpart Da. Emission standards, monitoring requirements, and performance testing are described for PM (opacity), SO_2 and NO_X.

The §60.42 Da standard for PM is 0.03 lb/MMBTU. Maximum PM anticipated from HRSG emissions is 0.011 lb/MMBTU. This section also contains an opacity standard of no greater than 20% (six-minute average) except for one six-minute period per hour of no more than 27%. Per §60.49Da(a)(2), as an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that burns only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO_2 or PM, may elect to monitor opacity using EPA Method 9 as specified in paragraph (a)(3) of this section..

The §60.43 Da standard for SO_2 is 340 ng/J (0.80 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input. Maximum SO_2 anticipated from HRSG emissions is 0.0056 lb/MMBTU, therefore the facility is in compliance. Sources using exclusively gaseous fuels are exempt from continuous monitoring of SO_2 per §60.49Da(b).

The §60.44Da standard for NO_X is 0.20 lb/MMBTU. Maximum NO_X anticipated from HRSG emissions is 0.08 lb/MMBTU. Continuous monitoring of NO_X is required per §60.49Da(c).

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

<u>Subpart GG,</u> (Stationary Gas Turbines) affects 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. Each of the proposed turbines has a higher heating value firing rate of 1,879 MMBTUH and is subject to this subpart. The turbines are governed by 40 CFR 60.332(b) and must satisfy the NO_X standard set forth in §60.332(a)(1). Standards specified in Subpart GG limit NO_X emissions to 87 ppmvd or less. Performance testing by Reference Method 20, conducted on April 1 through 6, 2003, for Block #1 and June 1 through 5, 2003, for Block #2 demonstrated that all four units and duct burners were in compliance with this standard and also with the permit standards. Monitoring fuel for nitrogen content was addressed in a letter dated May 17, 1996, from EPA Region 6. Monitoring of fuel nitrogen content shall not be required when pipeline-quality natural gas is the only fuel fired in the turbines. Sulfur dioxide standards specify that no fuel shall be used which exceeds 0.8% by weight sulfur nor shall exhaust gases contain in excess of 150 ppm SO_2. For fuel supplies without intermediate bulk storage, the owner or operator shall either monitor the fuel nitrogen and sulfur content daily or develop custom schedules of fuel analysis based on the characteristics of the fuel supply; these custom schedules must be approved by the Administrator before they can be used for compliance with monitoring requirements. The EPA Region 6 letter referenced above also states that when pipeline-quality natural gas is used exclusively, acceptable monitoring for sulfur is a quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly “stain tube” analysis.

<u>Subpart IIII</u>, (Stationary Compression Ignition Internal Combustion Engines), affects stationary compression ignition (CI) internal combustion engines (ICE) based on power and displacement ratings, depending on date of construction, beginning with those constructed after July 11, 2005.

For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator. Since the diesel fire pump was manufactured prior to 2009 and was not modified or reconstructed after July 11, 2005, there are no applicable requirements at this time.
Subpart KKKK, (Stationary Combustion Turbines), affects stationary combustion turbines that were commenced construction, modification, or reconstruction after February 18, 2005. The four (4) turbines at the facility were constructed prior to this date, and therefore not subject to this subpart.

NESHAP, 40 CFR Part 61 [Not Applicable]
Subpart C (Beryllium standard) affects certain processes that process beryllium ores, alloys or wastes. If this facility emits beryllium, it would be only trace or non-detectable amounts from combustion processes.
Subpart E (Mercury standard) affects certain sources which process mercury ore, use mercury chlor-alkali cells to produce chlorine, and incinerate or dry wastewater treatment plant sludge. If this facility emits mercury, it would be only in trace or non-detectable amounts from combustion processes.
Subpart J (Equipment Leaks of Benzene) affects fugitive emissions of benzene from certain equipment operated in benzene service (>10% benzene by weight). This facility emits benzene only in trace amounts from combustion processes and piping of natural gas. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.
Subparts N, O, and P (Arsenic standards) affects arsenic emissions from glass plants, copper smelters, and metallic arsenic production facilities. If this facility emits arsenic, it would be only in trace or non-detectable amounts from combustion processes.

NESHAP, 40 CFR Part 63 [Applicable]
There was no promulgated or proposed Maximum Achievable Control Technology (MACT) standard for the source category, “Combustion (Gas) Turbines,” however they are a listed source category pursuant to Section 112(c)(1) of the Clean Air Act when these turbines were installed. Since the stationary combustion turbines have potential major source emission levels, a Clean Air Act Section 112g case-by-case MACT determination for Hazardous Air Pollutants was performed.

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

KPP submitted a request for Notice of MACT Approval on August 9, 2000. They proposed a case-by-case MACT determination utilizing best combustion practices and combustion control procedures, including Dry Low NO_x burners and their inherent efficient fuel combustion. There were no control technologies that had been developed to control HAP emissions from combustion turbines. The use of add-on control technologies was limited to the two types of oxidation catalysts that were currently used primarily for CO control. The cost effectiveness of utilizing oxidation catalysts prohibited the use of these technologies for HAP control. This is a result of HAP emissions at a much lower level than CO emissions that are typically controlled. Therefore, combustion controls were proposed as case-by-case MACT for the Kiamichi Energy Facility.

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

A second principle states that the approved MACT "shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental and energy requirements associated with the emission reduction." The MACT analysis considered all known control technologies that were available and had taken into account the considerations listed above. Considerations for extremely high costs and unproven performance associated with such small reductions of HAP were the primary basis for exclusion of these technologies. Additional principles outlined in §63.43(d)(3) allow for MACT determinations to be based on a specific design, equipment, work practice operational standard or combination of these, when it has been demonstrated that it is not feasible to prescribe a specific emission limitation or control technology. The proposed case-by-case MACT submitted by KPP provided sufficient data to demonstrate that the available control technologies were not feasible or an appropriate means of establishing case-by-case MACT for this facility. Based on the principles prescribed in §63.43(d) for MACT determinations and the requirements of 40 CFR 63 Subpart B, a case-by-case MACT was approved for the four stationary combustion turbines constructed at the facility as best combustion control practices.

Subpart B Section 63.43 of Subpart B requires that any facility not included in a listed source category (or for which a standard has not been promulgated under Section 112c of the CAA prior to May 15, 2002) that constructs or reconstructs a major source of HAP after June 29, 1998, is subject to a case-by-case MACT determination. This "112g" MACT determination may be superseded by any subsequently promulgated MACT requirement promulgated under Section 112c of the CAA.
<u>Subpart YYYY</u> (Stationary Combustion Turbines) would affect this facility if it were a major source of HAP emissions. Based on test data submitted by the applicant, the facility does not appear to be a major source of HAP.
<u>Subpart Q</u> (Industrial Process Cooling Towers) applies to all new and existing industrial process cooling towers (IPCT) that are operated with chromium-based water treatment chemicals on or after September 8, 1994, and are either major sources or are integral parts of facilities that are major sources as defined in §63.401. This subpart prohibits the owner or operator of an IPCT from using chromium-based water treatment chemicals in any affected IPCT. This facility is not a major source of HAP and does not use chromium-based water treatment chemicals.

Subpart YYYY (Stationary Combustion Turbines) establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations. This subpart affects stationary combustion turbines located at a major source of HAP emissions. Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. The applicant has submitted test data to illustrate that the facility is not a major source of HAP.
Subpart ZZZZ, (Reciprocating Internal Combustion Engines (RICE)) affects existing, new, and reconstructed RICE located at major and area sources. The diesel fire pump engine was constructed before June 12, 2006 and is therefore an existing stationary RICE.
Subpart DDDDD, (Industrial, Commercial and Institutional Boilers and Process Heaters) affects industrial, commercial, and institutional boilers and process heaters at major sources of HAP. This facility is not a major source of HAP. Dealt
Subpart JJJJJJ, (Commercial and Institutional Boilers) affects new and existing boilers located at area sources of HAP, except for gas-fired boilers. Gas fired boilers are defined as any boiler that burns gaseous fuel not combined with any solid fuels, liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. The boilers at this facility meet the definition of gas fired boilers and are not subject to this subpart.

CAM, 40 CFR Part 64 [Not Applicable]
This part applies to any pollutant-specific emission 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

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

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
This facility does not process or store more than the threshold quantity of any regulated substance (Section 112r of the Clean Air Act 1990 Amendments). More information on this federal program is available on the web page: *www.epa.gov/rmp*

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
This facility is an affected source since it commenced operation after November 15, 1990, and is not subject to any of the exemptions under 40 CFR 72.7, 72.8 or 72.14. Paragraph 72.30(b)(2)(ii) requires a new source to submit an application for an Acid Rain permit at least 24 months prior to the start of operations. However, Mr. Dwight Alpern, U.S. EPA, has confirmed that this requirement was for the benefit of the regulating agency (Oklahoma DEQ) which can waive this requirement and has done so.

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

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

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

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

The standard conditions of the permit address the requirements specified at § 82.156 for persons opening appliances for maintenance, service, repair, or disposal; § 82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; § 82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; § 82.166 for recordkeeping; § 82.158 for leak repair requirements; and § 82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

Federal NO_X and SO_2 Trading Programs, 40 CFR Part 97 [Subpart EEEEE is Applicable]
Subpart EEEEE, Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program. This subpart establishes various provisions for the CSAPR NO_X Ozone Season Group 2 Trading Program, under Section 110 of the Clean Air Act and under the Federal Implementation Plan (FIP) codified under 40 CFR § 52.38. Under this subpart, the permittee is required to designate an official representative, monitor emissions, keep records, and make reports in accordance with §§ 97.830 through 97.835. The monitoring program must comply with 40 CFR Part 75 or an alternative monitoring program must be requested and approved. CSAPR NO_X Ozone Season Group 2 allowances are periodically allocated to the facility and at the completion of the allowance transfer deadline for the control period in a given year the permittee is required to hold, in the source's compliance account administered by the EPA Clean Air Markets Division (CAMD), sufficient allowances available for deduction for such control period under § 97.824(a) in an amount not less than the tons of total NO_X emissions for the control period from all CSAPR NO_X Ozone Season Group 2 units at the facility. The control period starts on May 1 of a calendar year, except as provided in § 97.806(c)(3), and ends on September 30 of the same year. For the CSAPR NO_X Ozone Season Group 2 Trading Program, the deadline for obtaining sufficient allowances is midnight of November 1 (if November 1 is a business day) or midnight of the first business day after November 1 (if November 1 is not a business day). Fines and future allowance deductions will be levied as described in § 97.806 if the permittee holds insufficient allowances at the completion of the allowance transfer deadline. The process of establishing an allowance account and requirements for administrating an account are included in § 97.820. The recording of allowance allocations is described in § 97.821. Submission and recording of allowance transfers is described in §§ 97.822 and 97.823. Compliance with ozone season emissions limitations and assurance provisions are described in §§ 97.824 and 97.825. Extra allowances may be banked (see § 97.826) and these vintage allowances may be used in later years with certain restrictions. These allowances do not constitute a property right. No Title V permit revision is required for any allocation, holding, deduction, or transfer of allowances in accordance with this subpart. The four (4) turbines at the facility are CSAPR NO_X Ozone Season Group 2 units subject to the requirements of this subpart. The permit includes the requirement to comply with all applicable requirements of this subpart.

SECTION VII. COMPLIANCE

Tier Classification and Public Review

This application has been determined to be Tier II based on the request for a construction permit that will result in a modification of a Part 70 source operating permit. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

The applicant has published a "Notice of Filing a Tier II Application" and "Notice of Tier II Draft Permit" in the *McAlester News-Capital*, a local newspaper in Pittsburg County on November 6, 2019. The notice stated that the draft application and permit was available for public review at the facility or the DEQ office in Oklahoma City. The notices also stated that the draft permit was available for public review at a local public library in Ponca City, Oklahoma. Information on all permit actions is available for review by the public in the Air Quality section of the DEQ Web page: www.deq.ok.gov/.

State Review
This facility is not located within 50 miles of the border of Oklahoma. Therefore, notice is not required to be sent to any state bordering Oklahoma.

EPA Review
The proposed permit was sent to EPA Region 6 for a 45 day review. No comments were received.

Fees Paid
A construction permit modification fee of $5,000 has been paid.

SECTION VIII. SUMMARY

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

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Kiowa Power Partners, LLC
Tenaska Kiamichi Generating Station **Permit Number 2014-1309-C (M-2) (PSD)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on May 7, 2019. The Evaluation Memorandum dated December 9, 2019, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emissions limitations for each point.

   a. Permittee shall maintain and operate the facility in a manner to prevent the exceedance of ambient air quality standards contained in OAC 252:100-3 and the limitations established by this permit.

Point ID#	EU Name/Model	Construct Date
Block 1, Unit 101	Combustion Turbine, GE PG7241FA, w/duct burner	11/24/2002
Block 1, Unit 201	Combustion Turbine, GE PG7241FA, w/duct burner	12/08/2002
Block 2, Unit 101	Combustion Turbine, GE PG7241FA, w/duct burner	01/11/2003
Block 2, Unit 201	Combustion Turbine, GE PG7241FA, w/duct burner	01/24/2003
Fire Pump	360-hp, Diesel Fire Pump	July 2002

	Each Combustion Turbine, without Duct Burners			
Pollutant	**lb/hr***	**TPY****	**ppmvd*****	**lb/MMBtu**
NO_X	63.0	275.94	9	
CO	31.0	135.78	9	
SO_2	10.6	46.43		0.0056****
VOC	3.00	13.14		
PM_{10}	13.06	57.19		
H_2SO_4	4.05	17.75		

*Three-hour rolling average (NO_X limit does not apply during periods of startup, shutdown, grid swaps, and black start tests)
**Annual monthly rolling average
***ppmv, dry basis, corrected to 15% oxygen, three-hour average. (NO_x limit does not apply during periods of startup, shutdown, grid swaps, and black start tests)
****modified by administrative amendment 6/14/01

Pollutant	Each Combustion Turbine, including Duct Burners lb/hr*	TPY**	Ppmvd***	lb/MMBtu
NO_X	115.00	455.52	15	
CO	70.00	270.47		
SO_2	14.27	59.09		0.0056****
VOC	25.75	91.71		
PM_{10}	20.40	82.55		
H_2SO_4	4.90	20.66		

*Three-hour rolling average (NO_X limit does not apply during periods of startup, shutdown, grid swaps, and black start tests)
**Annual monthly rolling average
***ppmv, dry basis, corrected to 15% oxygen, three-hour average. (NO_x limit does not apply during periods of startup, shutdown, grid swaps, and black start tests)
****modified by administrative amendment 6/14/01

Pollutant	Diesel Fire Pump lb/hr	TPY
NO_X	8.37	2.09
CO	1.80	0.45
VOC	0.68	0.17
SO_2	0.22	0.06
PM_{10}	0.59	0.15

b. During startups, shutdowns, grid swaps, and black start tests alternate short term emission limits apply to the combustion turbines. These limits shall not change the annual limits. The short term emission limits for each combustion turbine during startup, shutdown, grid swaps, and black start tests are shown below.

Event	Maximum Duration (hours)	NO_X Emissions (lbs/event)
Startup	4	802
Shutdown	1	217
Grid Swaps	4	802
Black Start Tests	4	802

c. “Startup” and “shutdown” hours shall be excluded from three-hour rolling averages for lb/hr and ppm_{vd} limits for NO_X. Annual limits must be attained at all times.

d. “Startup” shall be deemed to begin when fuel is supplied to the gas turbine and ends when the gas turbine reaches DLN (Dry Low NO_X) mode, Mode 6Q as directed by the control system. A signal indicating this mode from the turbine will be sent to the CEMS for SUSD limit calculations.

e. “Shutdown” shall be deemed to begin when the turbine exits the DLN mode. Shutdown ends with the termination of fuel flow to the turbine.

f. Emissions of hazardous air pollutants (HAP) shall not exceed 10 tons per year of any individual HAP nor shall exceed 25 tons per year of total combined HAP.

g. Emissions from the two cooling towers are limited to 14.1 lbs/hr TSP, combined total for both towers. Compliance with this limit shall be checked monthly using methods from AP 42, Fifth Edition, Volume I, Chapter 13: Miscellaneous Sources, 13.4 Wet Cooling Towers (Rev. 1/95).

2. Compliance with the authorized emission limits of Specific Condition No. 1, except the cooling towers, shall be demonstrated by monitoring fuel flow to each turbine, each duct burner, and initial performance testing designed to satisfy the requirements of federal NSPS Subpart GG and to confirm the manufacturer-guaranteed emission factors. In addition, the duration of each startup and shutdown shall be monitored and recorded.
[Permit No. 2000-103-C (M-1)(PSD)], [OAC 252:100-8-6(a)(1)]

a. All gas-fired combustion equipment shall be fueled using only pipeline natural gas containing no more than 2 grains of sulfur per 100 SCF gas. Compliance for this limit and for Subpart GG can be shown by the following methods: a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once per calendar year. All diesel-fired combustion equipment shall be fired on low sulfur diesel containing no more than 0.5% by weight sulfur. Compliance can be shown by the supplier's latest delivery ticket(s).
b. Fuel consumption is limited to 16,460,040 MMBTU per year at each combustion turbine and 4,489,550 MMBTU per year at each HRSG set of duct burners. Compliance shall be demonstrated monthly and 12-month rolling total.
c. CO Testing. At least once every other year permittee shall conduct performance testing for emissions of CO from all four turbine/duct burner sets during operating conditions that are representative of normal operation and furnish a written report to the AQD within 60 days of completion of the tests. If test results are less than 80% of the permit limits, then test frequency may be reduced to once during the term of the permit and another test will not be required during this permit term.

3. A serial number or another acceptable form of permanent (non-removable) identification shall be on each turbine. [Permit No. 2000-103-C (M-1)(PSD)]

4. Upon issuance of an operating permit, the permittee shall be authorized to operate the turbines and auxiliary boiler continuously (24 hours per day, every day of the year). The HRSG duct burners are limited to 6,907 hours per year. The fire pump shall each be limited to 500 hours of operation per 12-month rolling period.
[Permit No. 2000-103-C (M-1)(PSD)], [OAC 252:100-8-6(a)]

5. No emissions, from other than the duct burners, shall be discharged which exhibit greater than 20% opacity except for short-term occurrences not to exceed six minutes in any 60 minutes nor 18 minutes in any 24-hour period; in no case shall opacity exceed 60%. Emissions from the duct burners are subject to NSPS Da, and thus exempt from this requirement.

[Permit No. 2000-103-TV], [OAC 252:100-25]

6. The permittee shall incorporate the following BACT methods for reduction of emissions so as to meet the emission limitations as stated in Specific Condition No. 1.

[Permit No. 2000-103-TV], [OAC 252:100-8-5(d)(1)(A)]

   a. Each combustion turbine and duct burner shall be equipped with dry low-NO_X combustors.
   b. Emissions from the fire-water pump engine shall be controlled by properly operating per manufacturer's specifications, specified fuel types and limits as listed in Specific Condition #2.a.
   c. The cooling towers and drift eliminators shall be operated and maintained in accordance with the manufacturer's recommendations or standard industry practices to minimize emissions. Permittee shall follow manufacturer's recommendations or standard industry practices for repair or replacement of the drift eliminators.

7. The fire pump engine is subject to 40 CFR Part 63, Subpart ZZZZ and shall comply with all applicable requirements including but not limited to the following:

[40 CFR Subpart 63 Subpart ZZZZ]

   a. §63.6580 What is the purpose of subpart ZZZZ?
   b. §63.6585 Am I subject to this subpart?
   c. §63.6590 What parts of my plant does this subpart cover?
   d. §63.6595 When do I have to comply with this subpart?
   e. §63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?
   f. §63.6605 What are my general requirements for complying with this subpart?
   g. §63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?
   h. §63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?
   i. §63.6635 How do I monitor and collect data to demonstrate continuous compliance?
   j. §63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?
   k. §63.6655 What records must I keep?
   l. §63.6660 In what form and how long must I keep my records?
   m. §63.6665 What parts of the General Provisions apply to me?
   n. §63.6670 Who implements and enforces this subpart?
   o. §63.6675 What definitions apply to this subpart?

8. The turbines are subject to 40 CFR Part 60, Subpart GG, and shall comply with all applicable requirements. [40 CFR Part 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

9. The duct burners are subject to 40 CFR Part 60, Subpart Da, and shall comply with all applicable requirements. [40 CFR Part 60, Subpart Da]

    a. §60.42Da: Standard for particulate matter
    b. §60.43Da: Standard for sulfur dioxide
    c. §60.44Da: Standard for nitrogen oxides
    d. §60.48Da: Compliance Provisions
    d. §60.49Da: Emission monitoring
    e. §60.50Da: Compliance determination procedures and methods
    f. §60.51Da: Reporting requirements
    g. §60.52Da: Recordkeeping requirements

10. Fuel sulfur monitoring requirements of Condition No. 2.a are acceptable to meet the requirements of Subpart GG for natural gas fuel. Monitoring of fuel nitrogen content under Subpart GG shall not be required while commercial quality natural gas is the only fuel fired in the turbines.
[Permit No. 2000-103-C (M-1)(PSD)], [OAC 252:100-8-6 (a)(3)(B)], [OAC 252:100-43]

11. The permittee shall comply with all acid rain control permitting requirements for SO_2 emissions allowances and SO_2 and NO_x continuous emissions monitoring and reporting.
[Permit No. 2000-103-C (M-1)(PSD)], [OAC 252:100-8-6(a)(1)]

12. When monitoring shows an exceedance of the limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions including during start-up, shutdown, and malfunction of air pollution control equipment. Requirements include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions.
[Permit No. 2000-103-C (M-1)(PSD)], [OAC 252:100-9], [OAC 252:100-8-6(a)(1)], [OAC 252:100-43]

13. Block 1, Units 101 and 102 and Block 2, Units 101 and 102 are subject to the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program, 40 CFR Part 97, Subpart EEEEE. The permittee shall comply with all applicable requirements, including but not limited to: [40 CFR § 97.801 to § 97.835]

a. § 97.801 Purpose.
b. § 97.802 Definitions.
c. § 97.803 Measurements, abbreviations, and acronyms.
d. § 97.804 Applicability.
e. § 97.805 Retired unit exemption.
f. § 97.806 Standard requirements.
g. § 97.807 Computation of time.
h. § 97.808 Administrative appeal procedures.
i. § 97.810 State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.
j. § 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.
k. § 97.812 CSAPR NO_X Ozone Season Group 2 allowance allocations to new units.
l. § 97.813 Authorization of designated representative and alternate designated representative.
m. § 97.814 Responsibilities of designated representative and alternate designated representative.
n. § 97.815 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.
o. § 97.816 Certificate of representation.
p. § 97.817 Objections concerning designated representative and alternate designated representative.
q. § 97.818 Delegation by designated representative and alternate designated representative.
r. § 97.820 Establishment of compliance accounts, assurance accounts, and general accounts.
s. § 97.821 Recordation of CSAPR NO_X Ozone Season Group 2 allowance allocations and auction results.
t. § 97.822 Submission of CSAPR NO_X Ozone Season Group 2 allowance transfers.
u. § 97.823 Recordation of CSAPR NO_X Ozone Season Group 2 allowance transfers.
v. § 97.824 Compliance with CSAPR NO_X Ozone Season Group 2 emissions limitation.
w. § 97.825 Compliance with CSAPR NO_X Ozone Season Group 2 assurance provisions.
x. § 97.826 Banking.
y. § 97.827 Account error.
z. § 97.828 Administrator's action on submissions.
aa. § 97.830 General monitoring, recordkeeping, and reporting requirements.
bb. § 97.831 Initial monitoring system certification and recertification procedures.
cc. § 97.832 Monitoring system out-of-control periods.
dd. § 97.833 Notifications concerning monitoring.
ee. § 97.834 Recordkeeping and reporting.
ff. § 97.835 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

14. For any modification using "projected actual emissions" as defined in OAC 252:100-8-31, the permittee shall document and maintain a record of the information required by OAC 252:100-8-36.2(c)(1)(A) through (C). The permittee shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the modification and that is emitted by any emissions unit identified; and calculate and maintain a record of the annual emissions, in TPY on a calendar year basis, for a period of 5 years following resumption of regular operations after the modification, or for a period of 10 years following resumption of regular operations after the modification if it increases the design capacity or potential to emit of the affected emissions unit. The permittee shall submit a report to the Director if the annual emissions, in TPY, from the modification, exceed the baseline actual emissions (as documented and maintained) by an amount that is significant for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection for that modification. The report shall be submitted to the AQD within 60 days after the end of each year in which the exceedances or difference occurred. The report shall contain the information required by OAC 252:100-8-36.2(c)(5)(A) through (C). If the permittee materially fails to comply with these provisions, then the calendar year emissions are presumed to equal the source's potential to emit. [OAC 252:100-8-36.2(c)]

15. The permittee shall maintain records as listed below. These records shall be maintained on site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request.
[Permit No. 2000-103-C (M-1)(PSD)], [OAC 252:100-8-6 (a)(3)(B)]

a. CEMS data required by the Acid Rain program, and also heat value of fuel burned in the turbines and duct burners.
b. Operating hours for the turbine engines and the duct burners (monthly and 12-month rolling totals).
c. Total fuel consumption for each turbine and for each HRSG duct burner in units of MMBTU per year (monthly and 12-month rolling totals).
d. For the fuel(s) burned, the appropriate document(s) as described in Specific Condition 2.a, updated annually, or whenever the supplier changes.
e. Results of required testing.
f. Records required by NSPS Subparts Da, GG and NESHAP Subpart ZZZZ.
g. Records demonstrating compliance with the emissions limits on the cooling tower and records demonstrating proper operation and maintenance of the towers and drift eliminators, monthly.

16. Permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, an Annual Compliance Certification for each twelve (12) month period, no later than 30 days after June 30, 2010 and each 12 month anniversary date thereafter for the duration of this permit. The certification shall include a summary of any noncompliance with the permit or applicable regulations for the past year. Permittee shall also submit to Air Quality Division of DEQ, a Semi-Annual Monitoring and Deviation Report for each six (6) month

period, no later than 30 days after December 31, 2009 and June 30, 2010 and each six (6) month anniversary date thereafter for the duration of this permit.

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

17. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility.

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

a.	OAC 252:100-7	Permits for Minor Facilities
b.	OAC 252:100-11	Alternative Reduction
c.	OAC 252:100-15	Mobile Sources
d.	OAC 252:100-17	Incinerators
e.	OAC 252:100-23	Cotton Gins
f.	OAC 252:100-24	Feed & Grain Facility
g.	OAC 252:100-39	Nonattainment Areas
h.	OAC 252:100-47	Landfills

18. This permit replaces Air Quality permit No. 2000-103-C (M-1) (PSD) for this facility.

19. The permittee shall apply for an updated Title V operating permit within 180 days of operational start-up.

PART 70 PERMIT

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

Permit No. 2014-1309-C (M-2) (PSD)

Kiowa Power Partners, LLC,

having complied with the requirements of the law, is hereby granted permission to construct within their boundaries of their Tenaska Kiamichi Generating Station near Kiowa in Pittsburg County, Oklahoma, subject to standard conditions dated June 21, 2016 and specific conditions, both attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

Director	**Date**
Air Quality Department	

Larry Carlson
Kiowa Power Partners, LLC
14302 FNB Parkway
Omaha, NE 68007

SUBJECT: Permit Application No**. 2014-1309-C (M-2) (PDS)**
Tenaska Kiamichi Generating Station
Section 34, Township 3N, Range 13E
Pittsburg County, Oklahoma

Dear Mr. Carlson;

Air Quality Division has completed the initial review of your permit application referenced above. This application has been determined to be a **Tier II**. In accordance with 27A O.S. § 2-14-302 and OAC 252:4-7-13(c) the draft permit is now ready for public review. The requirements for public review of the draft permit include the following steps which you must accomplish:

1. Publish at least one legal notice (one day) in at least one newspaper of general circulation within the county where the facility is located. (Instructions enclosed).
2. Provide for public review (for a period of 30 days following the date of the newspaper announcement) a copy of this draft permit at a convenient location **within the county** of the facility (preferably at a public facility such as a local library).
3. Send AQD a written affidavit of publication for the notice from Item #1 above together with any additional comments or requested changes which you may have for the permit application within 20 days of publication.
4. At the end of the public review period, send AQD a written notice of any public comments that you may have received from the public.

After public review, a Proposed Permit will be submitted for EPA review. Contingent on public and EPA review, a final construction permit will be issued. Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact the permit writer at (405) 702-4209 or email to amalia.talty@deq.ok.gov.

Sincerely,

Phillip Fielder, P.E.
Chief Engineer,
Air Quality Division

Larry Carlson
Kiowa Power Partners, LLC
14302 FNB Parkway
Omaha, NE 68007

SUBJECT: Permit Number: 2014-1309-C (M-2) (PSD)
Tenaska Kiamichi Generating Station
Section 34, Township 3N, Range 13E
Pittsburg County, Oklahoma

Dear Mr. Carlson;

Enclosed is the permit authorizing construction 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. If you have any questions, please refer to the permit number above and contact me at (405) 702-4209.

Sincerely,

Amalia Talty, P.E.
New Source Permits Section
AIR QUALITY DIVISION

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]