OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **November 21, 2001**

TO:	Dawson Lasseter, P.E., Chief Engineer, Permits
THROUGH:	Eric Milligan, P.E., New Source Permits Unit Richard Kienlen, P.E., New Source Permits Unit
THROUGH:	Peer Review
FROM:	Phillip Fielder, P.E.
SUBJECT:	Evaluation of Permit Application No. **98-270-C (PSD) (M-1)** Associated Electric Cooperative, Inc. Chouteau Power Plant Mid America Industrial Park, Mayes County Directions: From the Mid America Industrial Park east off State Highway Route 412B and North on Robertson Street

SECTION I. INTRODUCTION

Associated Electric Cooperative, Inc. submitted an application for a minor modification to the referenced facility (SIC Code 4911) on September 4, 2001. The proposed modification will consist of increasing the hours of operation for the auxiliary boiler from 3,000 hours per year to continuous operation.

The facility currently consists of two combined cycle gas turbines with heat recovery steam generators and associated equipment producing a nominal total of 530 MW. Since the additional hours of operation will only occur during times that the turbines are not firing, this change will not result in any emission increases.

This review is limited to the proposed changes and incorporates all the requirements of the original permit. This permit will void the previous permit.

SECTION II. FACILITY DESCRIPTION

The facility contains a “two-on-one” combined cycle gas turbine (CCGT) plant firing exclusively natural gas. Hot exhaust gases from the gas turbines are passed through two separate drum-type heat recovery steam generators (HRSG) where the heat is converted to steam which drives a single conventional steam turbine that adds about 182 MW to the plant’s capacity. Waste heat is rejected through a condenser and mechanical draft-cooling tower.

Each of the two gas turbines are two Siemens KWU, Model V84.3A, advanced gas turbine design with a rated output of 176 MW (1,783 MMBTUH) at ISO conditions. This model utilizes Siemens' hybrid burner ring combustor designed for pre-mix firing above 60 percent output. This machine has a 15-stage compressor and 4-stage turbine. Advanced design features, in addition to the low-NOx hybrid-burner ring combustor, include single crystal blade castings and extensive use of film cooling. Film cooling ensures high cooling efficiency in the first two turbine stages. The design allows slightly higher firing temperatures, higher exhaust temperatures, and improved heat rate in both simple and combined cycle modes.

The HRSGs are three-pressure level boilers (low, intermediate, and high) with superheat and reheat sections. The gas turbines exhaust gases at about 1,050^{o}F that contact the boiler surfaces and transfer heat to the feedwater and steam. This arrangement enables higher efficiencies of the combined cycle power plant by using the exhaust gas energy. Each HRSG produces about 375,000 pounds of steam per hour at 1,566 psia and 1,016^{o}F. The HRSGs house a selective catalytic reduction (SCR) system for each unit to reduce NOx emissions.

The steam turbine is a Siemens K36-16/N36-2x6.9 two-cylinder tandem compound flow machine. The three electrical generators used to produce the nominal 530 MW are Siemens, Model TLRI-108/46-36, designed for dual drive from both the steam and gas turbines.

The cooling tower is a 9-cell mechanical draft tower with four to five cycles of concentration. Drift (water loss) from the tower is about 15,000-18,000 gallons (i.e., 0.005% of total water flow) per day at full load. Water treatment chemicals are non-chromium chemicals including sodium hypochlorite (14 lbs/day) and sulfuric acid (5000 gallons/year). The facility may also use NALCO 1333T, a scale inhibitor/corrosion inhibitor (300-310 lbs/day) and/or NALCO 7330 a non-oxidizing biocide (1200 lbs/year). In addition, a liquid dispersant, NALCO 8301 D is used at an approximate rate of 6.8 lbs/day.

The facility also includes an auxiliary boiler and a fuel gas heater that fire natural gas only and two pressurized 10,000 gallon anhydrous ammonia tanks. The auxiliary boiler is a Superior Boiler Works, Model No. 8, with a maximum design capacity of 33.6 MMBTUH. The design features include a low NOx burner control. The boiler is utilized to maintain the turbine system in hot-ready standby. This should help minimize the duration of the startup period for each turbine, which should lower the overall emissions and the amount of time spent in the diffusion mode (high emission levels) of operation. The boiler was originally not expected to operate more than 3,000 hours in a given year. However, the boiler will now be permitted for continuous usage and will normally be used only when the turbines are not in operation or during startup. The heater, rated at 12.2 MMBTUH, is used predominantly during winter months to heat a glycol/water solution which will circulate in a small heat exchanger preheating the supply of gas to prevent icing.

The proposed plant is designed for base load operation, but has the capability to cycle. Other than specified maintenance periods, the plant is designed to have an availability of over 90 percent. However, emissions estimates for this permit are based on continuous full 100% operations (100% load factor).

Other than startup, shutdown, and malfunctions, both combustion turbines are operated at above 60 percent rated turbine load to assure operations in the “pre-mix” mode. Pre-mix is the operating mode for the burner which optimizes combustion efficiency and produces the lowest NOx emissions. However, elevated levels of NOx and CO can result during cold startups and/or in the diffusion mode for periods up to 4 hours. Although the permit will limit the diffusion mode of operation to 4 hours, the auxiliary boiler should shorten this time to up to 3 hours, under normal operating conditions.

SECTION III. SCOPE OF REVIEW AND EMISSIONS

The combined-cycle combustion turbine power plant consists of five point sources: two turbine unit stacks, an auxiliary boiler stack, a fuel gas heater stack, and cooling tower. Since the facility exceeded the 100 TPY threshold for NOx and CO, the project was subject to full PSD review. Tier III public review, best available control technology (BACT), and ambient impacts analyses were also required.

The project was subject to NSPS Subpart GG for combustion turbines.

Full PSD review of emissions consisted of the following:

- 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
- evaluation of Class I area impact

Although the plant operates at a 70 to 75% capacity factor, short and long term emissions for the turbines were based on 100% load since this resulted in the highest emissions. Emissions were based on manufacturers guaranteed data and on a continuous operating period. Emissions from the cooling tower were based on a conservative estimate of 1000-ppm of Total Dissolved Solids (TDS) in the cooling tower drift and a total circulating water flow of 7,772,580 gallons per hour. The expected drift is approximately 18,000 gallons per day at full load and continuous operation. The analysis of raw water has indicated a TDS of 178 mg/l, which results in 890 mg/l at the maximum of 5 cycles of concentration. Fuel gas heater emissions are based on manufacturers data.

Auxiliary boiler emissions were originally based on manufacturer's data and a limit of 3,000 hours per year. This modification will now allow continuous operation. However, since the additional hours of operation will occur only during times that the turbines are not operating, total emissions will potentially be reduced by this change. The following calculated emissions remain unchanged from the original permit since this continues to represent worst case emissions.

Calculated Emissions

	Auxiliary Boiler		Fuel Gas Heater		Cooling Tower		Combustion Turbine #1		Combustion Turbine #2		Total Emissions	
Pollutant	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
NOx	2.36	3.54	2.40	11.00	N/A	N/A	86.70	379.75	86.70	379.75	178.16	774.04
SO_2	0.033	0.05	0.01	0.05	N/A	N/A	1.00	4.00	1.00	4.00	2.04	8.10
PM_{10}	0.335	0.50	0.08	0.40	3.47	15.22	5.00	22.00	5.00	22.00	13.89	60.12
VOC	0.536	0.80	0.09	0.40	N/A	N/A	5.02	22.00	5.02	22.00	10.67	45.20
CO	5.02	7.53	0.34	2.00	N/A	N/A	59.00	258.42	59.00	258.42	123.36	526.37
H_2SO_4	N/A	N/A	N/A	N/A	N/A	N/A	0.02	0.09	0.02	0.09	0.04	0.20

Significance Levels Comparisons
(TPY At Maximum Operation)

Pollutant	Emissions	PSD Significance Level	PSD Review Required
NOx	774	40	yes
CO	526	100	yes
VOC	45	40	yes
PM_{10}	60	15	yes
SO_2	8	40	no
H_2SO_4	0.20	7	no

SECTION IV. PSD REVIEW

As shown above, the proposed facility has potential emissions above the PSD significance levels for NOx, CO, VOC, and PM_{10} and required full review in the original permit.

As part of the full PSD review, a BACT analysis was conducted for all sources emitting any pollutant which exceeded a PSD-significant quantity. This update only considers the auxiliary boiler using the "top-down" methodology. The results indicate that the proposed increase in operating hours does not result in a new BACT determination.

Best Available Control Technology (BACT)

NOx BACT Review

NOx is produced through two mechanisms: thermal NOx and fuel NOx. High temperature processes create thermal NOx where nitrogen and oxygen gases in air react. Fuel NOx is created by combustion of nitrogen-containing materials.

The auxiliary boiler incorporates low-NO_x burners, uses good combustion control, and fires natural gas fuel exclusively. Given the inherent level of emissions based on low-NO_x controls, add-on controls such as SCR would not be cost effective. Thus, the use of good combustion control, using natural gas fuel exclusively, and incorporating low-NO_x burners represents BACT for the auxiliary boiler.

Carbon Monoxide BACT Review

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emission rates at acceptable levels.

Given the capacity of this boiler (33.6 MMBTUH max), the installation of add on CO controls would not be cost effective. Thus, the use of good combustion control and using natural gas fuel exclusively represents BACT for the auxiliary boiler.

Particulate Matter BACT Review

Particulate (PM_{10}) emissions from natural gas combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air and particulate of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions.

The most stringent particulate control method demonstrated for diesel engines is the use of low ash fuel (such as natural gas or low sulfur transportation diesel). Proper combustion control and the firing of fuels with negligible or zero ash content (natural gas for the auxiliary boiler) is the predominant control method listed.

The use of negligible or zero ash fuels such as natural gas and good combustion control are concluded to represent BACT for PM_{10} control in the auxiliary boiler.

VOC BACT Review

The control technologies evaluated for use on the natural gas-fired auxiliary boiler include catalytic oxidation and proper boiler design and good combustion practices. The cost of add-on controls on equipment of this size is prohibitive. However, optimizing boiler-operating conditions will minimize VOC emissions. The maximum estimated VOC emission rate is 0.54 lb/hr. Thus, boiler design and good operating practices are proposed as BACT for controlling VOC emissions from the auxiliary boiler. The proposed BACT will not have any adverse environmental or energy impacts.

Air Quality Impacts, Additional Impacts Analyses, and Class I Area Impact Analysis

The original impact analyses are not affected by this change since the worst case conditions that were used to demonstrate compliance does not change.

SECTION V. OKLAHOMA AIR QUALITY RULES

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

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. The primary standards are enumerated in Appendix E and the secondary standards are enumerated in Appendix F of the Air Pollution Control Rules (OAC 252:100). National Ambient Air Quality Standards (NAAQS) are established by the U.S. EPA. The actual ambient air concentration of criteria pollutants are monitored within the State of Oklahoma by ODEQ Air Quality Division. At this time, all of Oklahoma is in "attainment" of these standards. In addition, the facility modeled emissions from the proposed facility to demonstrate that the facility would not have a significant impact on air quality.

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

OAC 252:100-7 (Permits for Minor Facilities) [Not Applicable]
This facility is a major source because the total facility emissions are greater than 100 TPY of any regulated pollutant. An application for a modification to a major (Part 70) source requires processing under Subchapter 8.

OAC 252:100-8 (Major Source/Part 70 Permits) [Applicable]
The proposed facility has the potential to emit regulated pollutants in excess of 100 TPY. As such, a Title V (Part 70) operating permit application is required within 180 days of operation. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I <u>or</u> whose actual calendar year emissions do not exceed the following:

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

Since the facility proposed to change limitations set in the original permit, a modified permit is required. Emissions limitations have been established for each emission unit.

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

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

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
This Subchapter specifies a particulate matter (PM) emissions limitation of 0.20 lb/MMBTU from new and existing fuel-burning equipment with a rated heat input between 1,000 and 10,000 MMBTUH. The turbines, rated at 1,783 MMBTUH, are required to burn only commercial natural gas with a emission limit of 5 lb/hr. Based on these requirements, the turbines will have PM emissions of 0.003 lb/MMBTU, well below the Subchapter 19 limit. AP-42, Table 1.4-2 (3/98) lists PM emissions for the auxiliary boiler for natural gas to be 7.6 lb/MMcf or about 0.0076 lb/MMBTU. Based on manufacturer's data, the fuel heater will have emissions of 0.007 lb/MMBTU. Therefore, the auxiliary boiler and heater will be in compliance with Subchapter 19.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. All fuel-burning equipment on-site will use commercial natural gas, therefore, it is not necessary to specify any unique procedures to ensure compliance.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, 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/million BTU heat input. This is equivalent to approximately 0.2 weight percent sulfur in the fuel gas, which is equivalent to 2000 ppm sulfur. AP-42 states that commercial natural gas will have SO_2 emissions of 0.0006 lb/MMBTU. Thus, a limitation to only burn commercial natural gas will provide compliance for the boiler and turbines.
Part 5 also requires an opacity monitor and sulfur dioxide monitor for equipment rated above 250 MMBTUH. Since the turbines are limited to natural gas only, they are exempt from the opacity monitor requirement. Based on the commercial gas requirement, the natural gas burned at the site will have less than 0.1 percent sulfur and is, therefore, exempt from the sulfur dioxide monitor requirement.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits nitrogen oxides calculated as nitrogen dioxide from any new gas-fired fuel-burning equipment with a rated heat input of 50 MMBTUH or greater to a two-hour maximum of 0.20 lb/MMBTU. The maximum one-hour emission rates for the turbines based on the BACT requirement of 12 ppm is 86.70 lb/hr or 0.05 lb/MMBTU, which is in compliance.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
The project does not involve any of the following equipment: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires organic material storage tanks with a capacity of 400 gallons or more to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. No such tanks are located on-site.
Part 5 limits the organic solvent content of coating or other operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion. Combustion controls is a BACT requirement to minimize emissions.

OAC 252:100-41 (Hazardous and Toxic Air Contaminants) [Applicable**]**
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2000, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radio nuclides. General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, CC, DD, EE, GG, HH, II, JJ, LL, KK, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, and XXX are hereby adopted by reference as they exist on July 1, 2000. These standards apply to both existing and new sources of HAPs. NESHAP Regulations are covered in the "Federal Regulations" section.
Part 5 is a state-only requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category "A" pollutant above de minimis levels must perform a BACT analysis, and if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant, which exceeds the de minimis level, do not cause or contribute to a violation of the MAAC. The following table demonstrates the facility is in compliance with this subchapter.

Toxic emissions from the turbines are based on the draft AP-42 (5/98) Section 3.1 except for H_2SO_4 which is based on manufacturer's data. For the toxics with emissions above the de minimis levels, ISCST3 modeling for the same five year period was conducted and indicates the facility is in compliance with the applicable MAACs. In addition, ammonia emissions will result from ammonia injection in the SCR. The "ammonia slip" is based on manufacturer's data at 10 ppm NH_3 at the 12 ppm NOx control rate. Screen3 modeling was conducted and indicates the facility is in compliance.

			De Minimis Levels		Emissions	
Pollutant	**CAS #**	**Category**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
1,3-Butadiene	106990	A	0.57	0.60	0.002	0.009
Acetaldehyde	75070	B	1.1	1.2	0.28	1.23
Acrolein	107028	A	0.57	0.60	0.03	0.13
Ethylbenzene	100414	C	5.6	6.0	0.08	0.35
Formaldehyde	50000	A	0.57	0.60	11.89	52.08
Naphthalene	91203	B	1.1	1.2	0.49	2.15
NDMA*	62759	A	0.57	0.60	0.001	0.004
NMOR*	59892	A	0.57	0.60	0.001	0.004
PAHs*	14	A	0.57	0.60	0.63	2.76
Propylene Oxide	75569	A	0.57	0.60	0.10	0.44
Toluene	108883	C	5.6	6.0	0.45	1.97
TMA*	75503	C	5.6	6.0	0.001	0.004
Xylene	13300207	C	5.6	6.0	0.09	0.39
H_2SO_4	7664939	A	0.57	0.60	0.40	0.20
Arsenic	7440382	A	0.57	0.60	0.0002	0.001
Cadmium	7440439	A	0.57	0.60	0.003	0.013
Lead	7439921	NS	-	-	0.06	0.26
Manganese	7439965	C	5.6	6.0	0.006	0.03
Mercury	7439976	A	0.57	0.60	0.002	0.009
1,3-Butadiene	106990	A	0.57	0.60	0.002	0.009
Ammonia	7664417	C	5.6	6.0	36.28	158.91

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

Pollutant	**CAS #**	**Category**	**MAAC**	**24-hour Concentration**
Acetaldehyde	75070	B	3,600 ug/m^3	0.002 ug/m^3
Formaldehyde	50000	A	12 ug/m^3	0.068 ug/m^3
Naphthalene	91203	B	1,000 ug/m^3	0.003 ug/m^3
PAHs	14	A	1 ug/m^3	0.004 ug/m^3
Ammonia	7664417	C	1,742 ug/m^3	2.71 ug/m^3

OAC 252:100-43 (Sampling and Testing Methods) [Applicable]
All required testing must be conducted by methods approved by the Executive Director under the direction of qualified personnel. All required tests shall be made and the results calculated in accordance with test procedures described or referenced in the permit and approved by Air Quality.

OAC 252:100-45 (Monitoring of Emissions) [Applicable]
Records and reports as Air Quality shall prescribe on air contaminants or fuel shall be recorded, compiled, and submitted as specified in the permit.

SECTION VI. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
The facility qualifies as a listed facility based on being a fossil fuel-fired electric plant of more than 250 MMBTUH heat input. A complete PSD review was completed in permit No. 98-270-C (PSD). The proposed changes in this permit did not change any of the previous requirements.

NSPS, 40 CFR Part 60 [Applicable]
Subpart GG affects stationary gas turbines which commenced construction, reconstruction, or modification after October 3, 1977, with a heat input at peak load of greater than or equal to 10 MMBTUH based on the lower heating value of the fuel. The new turbines have heat input capacities at peak load of 1,783 MMBTUH and are, therefore, subject. Standards specified in Subpart GG limit NOx emissions to 87 ppmdv or less. Sulfur dioxide standards specified in Subpart GG are 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. For the NOx emissions, the BACT requirement of 12 ppm is more stringent than Subpart GG and is, therefore, applicable. While nitrogen content monitoring is not required for turbines burning exclusively pipeline-quality natural gas, monitoring under Acid Rain will be required to demonstrate continued compliance with the 12 ppm limit. For the SO_2 emissions, the facility is proposing to use only pipeline-grade natural gas which will contain less than the 0.8% sulfur by weight limit. Since pipeline-quality natural gas will be used exclusively, monitoring for sulfur is acceptable as a quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly “stain tube” analysis.
Subpart Dc affects industrial-commercial-institutional steam generating units with a design capacity between 10 and 100 MMBTUH heat input and which commenced construction or modification after June 9, 1989. For gaseous-fueled units, the only applicable standard of Subpart Dc is a requirement to keep records of the fuels used. The 33.6 MMBTUH gas-fired auxiliary boiler is an affected unit as defined as in the Subpart since the heating capacity is above the deminimis level. Record keeping will be specified in the permit.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, beryllium, coke oven emissions, radionuclides or vinyl chloride. The facility emits mercury and benzene but it is not one of the applicable sources and is, therefore, exempt from this part.

NESHAP, 40 CFR Part 63 [Not Applicable At This Time]
There is no current standard that applies to this facility. MACTs may be applicable under the source category “Stationary Turbines” which is scheduled for promulgation by May, 2002. Air Quality reserves the right to reopen this permit if any of these standards become applicable.

CAM, 40 CFR Part 64 [Applicable]
Compliance Assurance Monitoring (CAM) as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

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

The turbines are subject to CAM monitoring. CAM compliance methodologies are required to be submitted with the Title V operating permit application.

Accidental Release Prevention, 40 CFR Part 68 [Applicable]
The turbines burn natural gas only. Natural gas is a listed substance in CAAA 90 Section 112(r). However, this substance is not stored on site. The small quantity which is in the pipelines on the facility is much less than the 10,000 pound threshold and, therefore, is excluded from all requirements including the Risk Management Plan. However, AEC will store either aqueous or anhydrous ammonia in quantities exceeding the threshold amounts (10,000 pounds) for these substances. Therefore, AEC must submit a risk management plan to the proper authority by June 21, 1999, or as required based on the date of operation.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
This facility is an affected source since it is a simple cycle unit that commenced operation after November 15, 1990, and must submit an Acid Rain permit application in accordance with the requirements in 40 CFR 72.30. This is a simple cycle unit since no secondary firing occurs in the HRSG. 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, HQ U.S. EPA, (202) 564-9651, confirmed that this requirement was for the benefit of the regulating agency (Oklahoma DEQ) which could and in this case has waived this requirement.

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 (NOx Requirements) [Not Applicable]
This Part provides for NOx limitations and reductions for coal-fired utility units. Since the facility will fire natural gas only, it is exempt.

Stratospheric Ozone Protection, 40 CFR Part 82 [Applicable]
This facility does not produce, consume, recycle, import, or export any controlled substances or controlled products as defined in this part, nor does this facility perform service on motor (fleet) vehicles which involves ozone-depleting substances. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

VII. COMPLIANCE

Tier Classification And Public Review

The permit has been classified as a Tier I based on being a minor modification to an existing major source for which a Title V operating permit has not been issued. Information on all permit actions is available in the Air Quality section of the DEQ web page: *//www.deq.state.ok.us/*.

The applicant 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 real property. Information on all permit actions is available for review by the public on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*.

Fees Paid

Minor modification permit fee of $500.

VIII. SUMMARY

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

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Associated Electric Cooperative, Inc.
Chouteau Power Plant **Permit Number 98-270-C (PSD) (M-1)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on September 4, 2001. The Evaluation Memorandum, dated November 21, 2001, is attached to this permit to explain 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:

Combustion Turbine*

Pollutant	lb/hr	TPY	ppmdv**	lb/MMBTU
NOx	86.70	379.75	12	0.05
SO_2	1.00	4.00		
PM_{10}	5.00	22.00		0.003
VOC	5.02	22.00		
CO	59.00	258.42	10	
H_2SO_4	0.02	0.09		
Ammonia	18.14	79.46		

* each of two
** NOx and CO concentrations: parts per million by volume, dry basis, corrected to 15% oxygen.

	Auxiliary Boiler		Fuel Gas Heater		Cooling Tower	
Pollutant	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
NOx	2.36	10.34	2.40	11.00	N/A	N/A
SO_2	0.033	0.14	0.01	0.05	N/A	N/A
PM_{10}	0.335	1.48	0.08	0.40	3.47	15.22
VOC	0.536	2.35	0.09	0.40	N/A	N/A
CO	5.02	21.99	0.34	2.00	N/A	N/A

2. The fuel-burning equipment shall use only commercial-grade natural gas.

3. A serial number or another acceptable form of permanent (non-removable) identification shall be on each turbine.

4. Upon issuance of an operating permit, the permittee shall be authorized to operate the turbines and fuel gas heater continuously (24 hours per day, every day of the year). The auxiliary boiler shall be limited to 3,000 hours per year where operating hours are concurrent with that of either one or both combustion turbines. Auxiliary boiler operations shall not be restricted during periods in which both turbines are offline.

5. No emissions shall be discharged which exhibit greater than 20% opacity except for short-term occurrences not to exceed five minutes in any 60 minutes nor 20 minutes in any 24-hour period; in no case shall opacity exceed 60%.

6. The permittee shall incorporate the following BACT methods for reduction of emissions. Emission limitations are as stated in Specific Condition No. 1.

a. Emissions from each HRSG shall exit a stack through a properly operated and maintained SCR.

b. The turbine units shall have dry low-NOx burners.

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

a. 60.332: Standard for nitrogen oxides

b. 60.333: Standard for sulfur dioxide

c. 60.334: Monitoring of operations

d. 60.335: Test methods and procedures

8. Sulfur content monitoring of the fuel under NSPS Subpart GG is acceptable as a quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly "stain tube" analysis. Other customary monitoring procedures may be submitted with the operating permit for consideration. Monitoring of fuel nitrogen content under NSPS Subpart GG shall not be required while pipeline-quality natural gas is the only fuel fired in the turbines.

9. The permittee shall comply with all acid rain control permitting requirements and for SO_2 and NOx emissions allowances and continuous emissions monitoring and reporting.

10. During start-up, the facility shall not operate more than 4 hours outside the pre-mix mode or below 60 percent of rated turbine load.

11. The permittee shall maintain a record of the amount of natural gas burned in the auxiliary boiler for compliance with NSPS Subpart Dc.

12. Within 60 days of achieving maximum power output from the turbine, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing and furnish a written report to Air Quality documenting compliance with emissions limitations. Performance testing by the permittee shall use the following test methods specified in 40 CFR 60:

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4:	Determination of Moisture in Stack Gases.
Method 10:	Determination of Carbon Monoxide Emissions From Stationary Sources.
Method 20:	Determination of Nitrogen Oxides and Oxygen Emissions from Stationary Gas Turbines.
Method 25 or 25A:	Determination of Non-Methane Organic Emissions From Stationary Sources.

NOx and CO testing on the turbines shall be conducted at both the 100% and 60% operating rates, performance testing shall be conducted while the new units are operating within 10% of the desired testing rates.

13. When monitoring shows concentrations in excess of the ppm or lb/MMBTU limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions during start-up, shut-down, and malfunction of air pollution control equipment. Requirements include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions.

14. 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.

a. CEMS data required by the Acid Rain program.
b. Operating hours for the auxiliary boiler (monthly and cumulative annual).
c. Total fuel consumption (monthly and cumulative annual).
d. Sulfur content of natural gas (supplier statements or quarterly “stain-tube” analysis).

15. The permittee shall submit an update to the Title V operating permit application within 180 days of issuance of this permit. The update shall include method/methods to be used to demonstrate compliance with the auxiliary boiler hourly limits.

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

Date __________________________ Permit No. 98-270-C (PSD) (M-1)

Associated Electric Cooperative, Inc., having complied with the requirements of the law, is hereby granted permission to incorporate the modification at the Chouteau Power Plant located in the Mid America Industrial Park in Mayes County, OK,

subject to the following conditions, attached:

[X] Standard Conditions dated October 17, 2001

[X] Specific Conditions

____ Chief Engineer, Air Quality

DEQ Form 885
Revised 7/93

Associated Electric Cooperative, Inc.
Attn: Mr. Joel Miller
P.O. Box 754
Springfield, MO 65801-0754

Re:	Permit Number 98-270-C (PSD) (M-1)
	Chouteau Power Plant

Dear Mr. Miller:

Enclosed is the permit authorizing the modification to the construction permit for the referenced facility. Please note that this permit is issued subject to certain standard and specific conditions which are attached.

Thank you for your cooperation in this matter. If we may be of further service, please contact me at (405) 702-4203.

Sincerely,

Phillip Fielder, P.E.
New Source Permits Unit
AIR QUALITY DIVISION

cc: Mayes County DEQ Office