ADEQ

ARKANSAS
Department of Environmental Quality

December 30, 2009

Dustin Simpson
Air Quality Specialist
American Electric Power - Flint Creek Power Plant
P.O. Box 660164
Dallas, TX 75266

Dear Mr. Simpson:

The enclosed Permit No. 0276-AOP-R5 is issued pursuant to the Arkansas Operating Permit Program, Regulation # 26.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. 0276-AOP-R5 for the construction, operation and maintenance of an air pollution control system for American Electric Power - Flint Creek Power Plant to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8.603, within thirty (30) days after service of this decision.

All persons submitting written comments during the thirty (30) day, and all other persons entitled to do so, may request an adjudicatory hearing and Commission review on whether the decision of the Director should be reversed or modified. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,

Mike Bates
Chief, Air Division

ADEQ
OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 0276-AOP-R5
IS ISSUED TO:

American Electric Power - Flint Creek Power Plant
21797 SWEPCO Plant Road
Gentry, AR 72734
Benton County
AFIN: 04-00107

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

December 29, 2005 AND December 28, 2010

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates
Chief, Air Division

December 30, 2009
Date

American Electric Power - Flint Creek Power Plant
Permit #: 0276-AOP-R5
AFIN: 04-00107

Table of Contents

List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than Ten Microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	American Electric Power - Flint Creek Power Plant
AFIN:	04-00107
PERMIT NUMBER:	0276-AOP-R5
FACILITY ADDRESS:	21797 SWEPCO Plant Road Gentry, AR 72734
MAILING ADDRESS:	P.O. Box 660164 Dallas, TX 75266
COUNTY:	Benton County
CONTACT NAME:	Dustin Simpson
CONTACT POSITION:	Air Quality Specialist
TELEPHONE NUMBER:	214-777-1282
REVIEWING ENGINEER:	Ambrosia Brown
UTM North South (Y):	Zone 15: 4013449.34 m
UTM East West (X):	Zone 15: 363123.06 m

SECTION II: INTRODUCTION

Summary of Permit Activity

AEP-Southwestern Electric Power Company (SWEPCO) and the Arkansas Electric Cooperative Corporation (AECC) jointly own the Flint Creek Power Plant, with AEP-SWEPCO being the plant operator. This facility is located at 21797 SWEPCO Plant Road, Gentry, Arkansas. The Flint Creek Power Plant produces power using a 558 MW boiler (SN-01). The boiler may operate under three scenarios: coal firing, coal and tire derived fuel firing, and leachate injection while coal firing.

This permitting action is necessary to allow the direct injection of leachate from the fly ash landfill into the boiler (SN-01) for evaporation. This modification increases the permitted emissions by 2.1 tpy PM/PM_{10}.

Process Description

The boiler burns primarily low sulfur western coal. The coal is supplied via railcar and dumped into a hopper. The coal from the hopper dumps onto an enclosed conveyor and is transported to the coal transfer house. At the coal transfer house the coal is transferred by conveyor to either the coal pile or the coal tripper house. Coal from the tripper house goes to the coal bunker, is pulverized and injected into the boiler for combustion. Coal may be reclaimed from the coal pile using hoppers located underneath the coal pile and conveying the coal back to the coal transfer house.

Fly ash resulting from the coal combustion process is collected by two hot side electrostatic precipitators. The collected fly ash is pneumatically conveyed to a fly ash silo and is shipped offsite for reuse or to the fly ash landfill. Leachate from the fly ash landfill is collected through a leachate collection system. Leachate is transferred from the collection system located at the fly ash landfill to a storage tank located near the boiler by way of truck or pipe line. During the leachate injection while coal firing scenario, leachate is pumped directly into the boiler at a maximum rate of 50gpmm from the storage tank. Flue gas laden with ash from coal combustion and evaporation of leachate will travel through a electrostatic precipitator, where it is collected.

One of the operating scenarios for the facility includes coal and tire derived fuel firing. The TDF is transported by truck from a supplier and then is blended in the same manner as the straight coal prior to placement into the reclaim hopper. The coal and TDF mixture from the hopper is then dumped onto an enclosed conveyor and transported to the coal transfer house (SN-06). Then the mixture is transferred by the coal bunker conveyor (SN-05) to the tripper house. It is then transferred to the coal bunker silos (SN-04) before being pulverized and injected into the boiler (SN-01) for combustion.

Additional emission points include one fuel oil storage tank (SN-18), two used oil storage tanks, a gasoline storage tank (SN-15) for fueling vehicles, a diesel storage tank (SN-14) for fueling

vehicles and off-road equipment, and three small degreasing units. The permittee also maintains an emergency generator diesel engine and an emergency fire pump diesel engine.

There is a proposed flyash railcar loading facility which will not be owned by Flint Creek, but which will be located on this facility's property. This activity is not incorporated into this air permit. It is addressed separately by the Department.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective January 25, 2009
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective July 18, 2009
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective January 25, 2009
40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971
40 CFR Part 64 – Compliance Assurance Monitoring
40 CFR Parts 72, 73, 75, 76, 77 – Acid Rain Program
40 CFR Part 82 – Protection of Stratospheric Ozone

American Electric Power - Flint Creek Power Plant
Permit #: 0276-AOP-R5
AFIN: 04-00107

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

The source for the stated maximum hourly and maximum annual emissions was provided by the permittee in the form of emission rate tables and emission calculations included as part of Flint Creek's Air Quality Operating Permit Renewal Application as hand-delivered to the ADEQ on October 8, 2003, and / or as subsequently revised in correspondence submitted to the ADEQ in 2004 and 2005

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	821.5	3,127.9
		PM_{10}	797.0	3,085.2
		SO_2	7,588.8	29,915.0
		VOC	44.2	98.6
		CO	822.3	3,241.8
		NO_X	4,426.8	17,450.4
		Lead*	0.07	0.25
HAPs		Acetaldehyde*	0.24	0.93
		Acetophenone*	0.01	0.03
		Acrolein*	0.12	0.48
		Antimony*	0.01	0.03
		Arsenic*	0.17	0.67
		Benzene*	0.54	2.11
		Benzyl Chloride*	0.29	1.14
		Beryllium*	0.01	0.04
		Bis(2-ethylhexyl)phthalate (DEHP)*	0.04	0.12
		Bromoform*	0.02	0.07
		Cadmium*	0.03	0.09
		Carbon Disulfide*	0.06	0.22
		2-Chloroacetophenone*	0.01	0.02
		Chlorobenzene*	0.01	0.04
		Chloroform*	0.03	0.10
		Chromium*	0.11	0.43
		Chromium VI*	0.04	0.13

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Cobalt*	0.05	0.17
		Cumene*	0.01	0.01
		Cyanide*	1.03	4.06
		2,4-Dinitrotoluene*	0.01	0.01
		Dimethyl Sulfate*	0.02	0.08
		Ethyl Benzene*	0.04	0.16
		Ethyl Chloride*	0.02	0.07
		Ethylene Dichloride*	0.02	0.07
		Ethylene Dibromide*	0.01	0.01
		Formaldehyde*	0.71	2.80
		Hexane*	0.03	0.11
		Hydrogen Chloride	43.35	170.89
		Hydrogen Fluoride	61.02	240.54
		Isophorone*	0.24	0.95
		Manganese*	0.21	0.80
		Mercury*	0.04	0.14
		Methyl Bromide*	0.07	0.26
		Methyl Chloride*	0.22	0.86
		Methyl Ethyl Ketone*	0.17	0.64
		Methyl Hydrazine*	0.07	0.28
		Methyl Methacrylate*	0.01	0.04
		Methyl Tert Butyl Ether*	0.02	0.06
		Methylene Chloride	0.12	0.48
		Nickel*	0.12	0.46
		Phenol*	0.16	0.62
		Polycyclic Organic Matter*	0.02	0.06
		Polynuclear Aromatic Hydrocarbons*	0.02	0.06
		Propionaldehyde*	0.16	0.62
		Selenium*	0.54	2.11
		Styrene*	0.02	0.05
		Tetrachloroethylene	0.02	0.07
		Toluene*	0.10	0.39
		1,1,1-Trichloroethane*	0.01	0.04
		Vinyl Acetate*	0.01	0.02
		Xylenes*	0.02	0.06
Air Contaminants		Sulfuric Acid**	5.82	25.48
SN-01	Boiler	PM	778.4	3,068.4
		PM_{10}	778.4	3,068.4
		SO_2	7,588.8	29,915.0

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		VOC	24.7	97.3
		CO	822.3	3,241.8
		NO_x	4,426.8	17,450.4
		Lead*	0.07	0.25
		Acetaldehyde*	0.24	0.93
		Acetophenone*	0.01	0.03
		Acrolein*	0.12	0.48
		Antimony*	0.01	0.03
		Arsenic*	0.17	0.67
		Benzene*	0.54	2.11
		Benzyl Chloride*	0.29	1.14
		Beryllium*	0.01	0.04
		Bis(2-ethylhexyl)phthalate (DEHP)*	0.04	0.12
		Bromoform*	0.02	0.07
		Cadmium*	0.03	0.09
		Carbon Disulfide*	0.06	0.22
		2-Chloroacetophenone*	0.01	0.02
		Chlorobenzene*	0.01	0.04
		Chloroform*	0.03	0.10
		Chromium*	0.11	0.43
		Chromium VI*	0.04	0.13
		Cobalt*	0.05	0.17
		Cumene*	0.01	0.01
		Cyanide*	1.03	4.06
		2,4-Dinitrotoluene*	0.01	0.01
		Dimethyl Sulfate*	0.02	0.08
		Ethyl Benzene*	0.04	0.16
		Ethyl Chloride*	0.02	0.07
		Ethylene Dichloride*	0.02	0.07
		Ethylene Dibromide*	0.01	0.01
		Formaldehyde*	0.71	2.80
		Hexane*	0.03	0.11
		Hydrogen Chloride	43.35	170.89
		Hydrogen Fluoride	61.02	240.54
		Isophorone*	0.24	0.95
		Manganese*	0.21	0.80
		Mercury*	0.04	0.14
		Methyl Bromide*	0.07	0.26
		Methyl Chloride*	0.22	0.86
		Methyl Ethyl Ketone*	0.17	0.64

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Methyl Hydrazine*	0.07	0.28
		Methyl Methacrylate*	0.01	0.04
		Methyl Tert Butyl Ether*	0.02	0.06
		Methylene Chloride	0.12	0.48
		Nickel*	0.12	0.46
		Phenol*	0.16	0.62
		Polycyclic Organic Matter*	0.02	0.06
		Polynuclear Aromatic Hydrocarbons*	0.02	0.06
		Propionaldehyde*	0.16	0.62
		Selenium*	0.54	2.11
		Styrene*	0.02	0.05
		Tetrachloroethylene	0.02	0.07
		Toluene*	0.10	0.39
		1,1,1-Trichloroethane*	0.01	0.04
		Vinyl Acetate*	0.01	0.02
		Xylenes*	0.02	0.06
		Sulfuric Acid**	5.82	25.48
SN-02	Fly Ash Silo	PM PM_{10}	0.1 0.1	0.1 0.1
SN-03	Coal Car Dumper	PM PM_{10}	0.3 0.1	0.2 0.1
SN-04	Coal Bunker	PM PM_{10}	0.1 0.1	0.1 0.1
SN-05	Coal Bunker Conveyor	PM PM_{10}	0.1 0.1	0.3 0.2
SN-06	Coal Transfer House	PM PM_{10}	0.3 0.1	0.2 0.1
SN-07	Coal Storage Pile	PM PM_{10}	39.1 16.9	54.3 15.5
SN-08	Ash Landfill	PM PM_{10}	3.1 1.2	4.3 0.7
SN-14	Diesel Storage Tank	VOC	0.5	0.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-15	Gasoline Storage Tank	VOC	18.3	0.9
SN-18	Fuel Oil Storage Tank	VOC	0.7	0.3

*HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
**Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

SECTION III: PERMIT HISTORY

The Flint Creek Power Plant was originally permitted in 1975 under permit 276-A. The original permit did not specify hourly or annual emission rates. Permit 276-A is the only permit issued to the permittee prior to the issuance of the initial operating permit.

276-AOP-R0 was issued on April 8, 1999. This was the initial Title V permit. The permit included the option to burn tire derived fuel as a supplemental fuel for the boiler.

276-AOP-R1 was issued on June 2, 2000. This minor modification was necessary to correct typographical errors and remove Operating Scenario 3 (coal and fuel oil co-firing) and Operating Scenario 4 (fuel oil only firing). The operating scenarios are used during startup and shutdown and not for the production of electricity. On September 17, 2001, this permit was administratively amended for typographical errors. On Page 19, Specific Condition 34, daily records were required for opacity readings for SN-03. The previous revision 276-AOP-R0 required weekly records. There were no records, notes, or correspondence found indicating the reason for changing record keeping frequency from weekly (276-AOP-R0) to daily (276-AOP-R1). Thus, the requirement was changed back to weekly records on September 17, 2001 by an Administrative Amendment to 276-AOP-R1.

276-AOP-R2 was issued on December 29, 2005. In addition to renewing the facility's Title V air permit, this permitting action was necessary to: permit emissions of hazardous air pollutants (HAPs); update the permitted hourly emission rates for SN-14, SN-15, and SN-18 based on Tanks 4.0 emission estimation software; increase the permitted annual throughput of SN-18 to 6,662,560 gallons per year; increase the permitted annual coal usage rate to 3,237,560 tons per year; increase the permitted hourly throughput of SN-03 and SN-06 to the maximum capacity of the equipment; update the requirements for SN-14 in accordance with the changes to 40 CFR Part 60, Subpart Kb (removed Subpart Kb requirements for SN-14 since this tank is less than the new applicability threshold of $75m^3$); add a new stack testing requirement for PM to demonstrate compliance with Compliance Assurance Monitoring requirements; add new stack testing requirements for PM, PM_{10}, and CO; and add new Arsenic and Lead stack testing requirements for Scenario 2. This permitting action resulted in permitted emission increases of 190.0 tons per year (tpy) PM; 161.7 tpy PM_{10}; 1,837.4 tpy SO_2; 6.6 tpy VOC; 203.1 tpy CO; 1,071.8 tpy NO_X; and all hazardous air pollutant and air contaminant emission rates for this facility increased due to these pollutants previously not being permitted. This action did not require PSD review because there was no modification to the equipment and the previous coal throughput limits were not PSD limits.

276-AOP-R3 was issued on September 5, 2007. This permitting action was issued as part of a Permit Appeal Resolution. The following changes were made with this permit modification in accordance with the Permit Appeal Resolution: increase the PM and PM_{10} lb/hr and tpy emission rate limits at SN-01 to include condensables. There were no actual changes to the boilers; increase the HCl and HF emission rate limits at SN-01 to reflect the maximum chlorine and fluorine content of the coal; remove the chlorine and fluorine coal content limits; allow for No. 2 Fuel Oil usage at SN-01 for activities not already included in the permit until a written

determination from EPA has been received; remove the requirement that the initial PM test at SN-01 be conducted at 20% opacity; specify compliance method for opacity for fugitive emissions at SN-02 fly ash silo; reword the opacity observations condition at SN-02; remove the 20% opacity limit for SN-03, SN-07, and SN-08; require no nuisance beyond property boundary for SN-03, SN-05, SN-06, SN-07, and SN-08; add an exception for use of water sprays at SN-03, SN-06, and SN-07 when it is below 40 degrees F or while it is raining; specify vents for the baghouse opacity limits (SN-02 and SN-04); revise opacity recordkeeping for SN-04; replace 20% opacity limit at SN-05 and SN-06 with reference to Plantwide Condition #5; maximize the permitted roadway emissions at SN-07 and SN-08; and remove the vehicle miles traveled limits at SN-07 and SN-08. The following changes were made in this permit modification in addition to those agreed upon in the Permit Appeal Resolution: change the regulatory citation of Specific Condition #3 to §19.304 of Regulation 19 and 40 CFR Part 60, Subpart D; include a copy of the CAM Plan, Corrective Action Plan, and Attachment A to the Corrective Action Plan in Appendix C; change the reference in Specific Condition #30 from 40 CFR Part 75.8 to 40 CFR Part 75; and increase the limit on hours of boiler and condenser non-hazardous chemical cleaning waste evaporation. This permitting action resulted in permitted emission increases of 589.2 tons per year (tpy) PM; 577.5 tpy PM_{10}; 150.76 tpy HCl; and 168.51 tpy HF. There were no physical changes or changes in the method of operation. On January 15, 2008, an administrative amendment was issued that added placing residual fire fighter training refuse and small amounts of soil and/or water contaminated with diesel fuel and/or oil onto the coal pile as an insignificant activity and updated the effective date of Regulation 19.

0276-AOP-R4 was issued on March 19, 2009. This permitting action was necessary to incorporate requirements from the Clean Air Interstate Rule and add the Soil Sement to the insignificant activities list. The permitted emission rate limits remained unchanged for this modification.

SECTION IV: SPECIFIC CONDITIONS

SN-01
Boiler

Source Description

The Flint Creek Power Plant produces power using a boiler (SN-01) to produce sufficient steam to operate the turbine generator at the 558 megawatt gross electrical output capability of the unit. The boiler burns primarily low sulfur western coal, but can also combust fuel oil and tire derived fuels. Fuel oil firing is only allowed during unit startup and shutdown, startup and shutdown of pulverizer mills, for flame stabilization when coal is frozen, No. 2 fuel oil tank maintenance, to prevent boiler tube failure in extreme cold weather when the unit is offline for maintenance, and malfunction (as specified in Specific Condition #15). Fly ash resulting from the coal combustion process is collected by two hot side electrostatic precipitators. The boiler has three (3) operating scenarios:

Scenario 1: coal firing;
Scenario 2: coal and tire derived fuel (TDF) co-firing;
Scenario 3: leachate injection while coal firing

EPA Region VI has determined that performance testing for PM in accordance with 40 CFR 60.46 is not required for the coal and fuel oil co-firing scenario, due to the fact that this scenario is not considered "representative" based on the information contained in the permittee's letter dated August 22, 1995. A waiver in accordance with 40 CFR 60.8(b)(4) from the PM testing requirement is not required pursuant to 40 CFR 60.8(c).

Specific Conditions

SCENARIO 1: COAL FIRING SPECIFIC CONDITIONS

1. The permittee shall not exceed the emission rates set forth in the following table for SN-01, when operating under Scenario 1: Coal Firing. [Regulation 19, §19.501 et seq., effective July 18, 2009 and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr
PM_{10}	777.9
SO_2	7,588.8
VOC	24.6
CO	821.3

Pollutant	lb/hr
NO_x	4,426.8
Lead	0.07

2. The permittee shall not exceed the emission rates set forth in the following table for SN-01, when operating under Scenario 1: Coal Firing. [Regulation 18, §18.801, effective January 25, 2009, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr
PM	777.9
Acetaldehyde	0.24
Acetophenone	0.01
Acrolein	0.12
Antimony	0.01
Arsenic	0.17
Benzene	0.54
Benzyl Chloride	0.29
Beryllium	0.01
Bis(2-ethylhexyl)phthalate (DEHP)	0.03
Bromoform	0.02
Cadmium	0.03
Carbon Disulfide	0.06
2-Chloroacetophenone	0.01
Chlorobenzene	0.01
Chloroform	0.03
Chromium	0.11
Chromium VI	0.04
Cobalt	0.05
Cumene	0.01
Cyanide	1.03

Pollutant	lb/hr
2,4-Dinitrotoluene	0.01
Dimethyl Sulfate	0.02
Ethyl Benzene	0.04
Ethyl Chloride	0.02
Ethylene Dichloride	0.02
Ethylene Dibromide	0.01
Formaldehyde	0.71
Hexane	0.03
Hydrogen Chloride	43.35
Hydrogen Fluoride	61.02
Isophorone	0.24
Manganese	0.21
Mercury	0.04
Methyl Bromide	0.07
Methyl Chloride	0.22
Methyl Ethyl Ketone	0.17
Methyl Hydrazine	0.07
Methyl Methacrylate	0.01
Methyl Tert Butyl Ether	0.02
Methylene Chloride	0.12
Nickel	0.12
Phenol	0.16
Polycyclic Organic Matter	0.02
Polynuclear Aromatic Hydrocarbons	0.02
Propionaldehyde	0.16
Selenium	0.54
Styrene	0.02

Pollutant	lb/hr
Tetrachloroethylene	0.02
Toluene	0.10
1,1,1-Trichloroethane	0.01
Vinyl Acetate	0.01
Xylenes	0.02
Sulfuric Acid	5.82

3. SN-01 (boiler) is subject to 40 CFR, Part 60, Subpart A, General Provisions and 40 CFR, Part 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators due to a heat input capacity greater than 250 million British Thermal Units per hour (MMBtu/hr) and installation after August 17, 1971. 40 CFR, Part 60, Subpart D is provided as Appendix A. Applicable provisions of Subpart D for the coal firing scenario, include, but are not limited to:

   a. Pursuant to 40 CFR 60.42(a)(1), PM emissions shall not exceed 0.1 lb/MMBtu.
   b. Pursuant to 40 CFR 60.42(a)(2), opacity shall not exceed 20%, except for one six-minute period per hour of not more than 27 percent opacity.
   c. Pursuant to 40 CFR 60.43(a)(2), SO_2 emissions shall not exceed 1.2 lb/MMBtu.
   d. Pursuant to 40 CFR 60.44(a)(3), NO_x emissions shall not exceed 0.7 lb/MMBtu.
   e. Pursuant to 40 CFR 60.45(a), the permittee shall install, calibrate and maintain Continuous Emissions Monitoring Systems (CEMS) for NO_x, SO_2, opacity, and carbon dioxide (CO_2). According to 60.45(b)(3), Flint Creek is not required by 40 CFR Part 60, Subpart D to monitor (CEMS) for NO_X due to the actual NO_X emissions being demonstrated to be less than 70% of the NSPS standard (0.70 lbMMBtu) during the initial performance test.
   f. Pursuant to 40 CFR 60.45(g)(1), excess opacity emissions are defined as any six minute period during which the average opacity emissions exceed 20%, except for one 6- minute average per hour of up to 27 percent opacity.
   g. Pursuant to 40 CFR 60.45(g)(2), excess SO_2 emissions are defined as any three hour period during which the average emissions (arithmetic average of three contiguous one hour periods) of SO_2 as measured by a CEMS exceed the applicable standard under 60.43 (item c).
   h. Pursuant to 40 CFR 60.45(g)(3), excess NO_x emissions are defined as any three hour period during which the average emissions (arithmetic average of three contiguous one hour periods) of NO_x as measured by a CEMS exceed the applicable standard under 60.44 (item d). According to 60.45(b)(3), Flint Creek is not required by 40 CFR Part 60, Subpart D to monitor (CEMS) for NO_X due to the actual NO_X emissions being demonstrated to be less than 70% of the NSPS standard (0.70 lbMMBtu) during the initial performance test.

i. Pursuant to 40 CFR 60.45(g), excess emission and monitoring system performance reports shall be submitted to the ADEQ for every calendar quarter. Quarterly reports shall be postmarked by the 30th day following the end of the calendar quarter. Excess emissions are defined in 60.45(g). Due to the facility having demonstrated that actual NO_X emissions are less than 70% of the federal standard (0.7 lb/MMBtu), quarterly excess NO_X emission reports are not required.

j. Pursuant to 40 CFR 60.46(a), the permittee shall conduct an initial compliance test for PM and pursuant to 40 CFR 60.46(b)(2) testing shall be conducted using EPA reference method 5. (Testing was conducted June 19, 1979).

[§19.304 of Regulation 19, and 40 CFR 60, Subpart D]

4. The permittee shall maintain records which demonstrate compliance with the hourly SO_2 emission limit set in Specific Condition 1 and may be used by the Department for enforcement purposes. Compliance shall be determined as the average emissions (arithmetic average of three contiguous one hour periods) of SO_2 as measured by a CEMS and converted to pounds per hour using corresponding average (arithmetic average of three contiguous one hour periods) stack gas flow rates. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

5. The permittee shall maintain records which demonstrate compliance with the hourly NO_x emission limit set in Specific Condition 1 and may be used by the Department for enforcement purposes. Compliance shall be determined as the average emissions (arithmetic average of three contiguous one hour periods) of NO_x as measured by a CEMS and converted to pounds per hour using corresponding average (arithmetic average of three contiguous one hour periods) stack gas flow rates. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

SCENARIO 2: COAL AND TDF CO-FIRING SPECIFIC CONDITIONS

6. The permittee shall not exceed the emission rates set forth in the following table for SN-01, when operating under Scenario 2: Coal and Tire Derived Fuel (TDF) Co-firing. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr
PM_{10}	777.9
SO_2	7,588.8
VOC	24.7
CO	822.3

Pollutant	lb/hr
NO_x	4,426.8
Lead	0.07

7. The permittee shall not exceed the emission rates set forth in the following table for SN-01, when operating under Scenario 2: Coal and Tire Derived Fuel (TDF) Co-firing. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr
PM	777.9
Acetaldehyde	0.24
Acetophenone	0.01
Acrolein	0.12
Antimony	0.01
Arsenic	0.17
Benzene	0.54
Benzyl Chloride	0.29
Beryllium	0.01
Bis(2-ethylhexyl)phthalate (DEHP)	0.04
Bromoform	0.02
Cadmium	0.03
Carbon Disulfide	0.06
2-Chloroacetophenone	0.01
Chlorobenzene	0.01
Chloroform	0.03
Chromium	0.11
Chromium VI	0.04
Cobalt	0.05
Cumene	0.01
Cyanide	1.03

Pollutant	lb/hr
2,4-Dinitrotoluene	0.01
Dimethyl Sulfate	0.02
Ethyl Benzene	0.04
Ethyl Chloride	0.02
Ethylene Dichloride	0.02
Ethylene Dibromide	0.01
Formaldehyde	0.71
Hexane	0.03
Hydrogen Chloride	43.35
Hydrogen Fluoride	61.02
Isophorone	0.24
Manganese	0.21
Mercury	0.04
Methyl Bromide	0.07
Methyl Chloride	0.22
Methyl Ethyl Ketone	0.17
Methyl Hydrazine	0.07
Methyl Methacrylate	0.01
Methyl Tert Butyl Ether	0.02
Methylene Chloride	0.12
Nickel	0.12
Phenol	0.16
Polycyclic Organic Matter	0.02
Polynuclear Aromatic Hydrocarbons	0.02
Propionaldehyde	0.16
Selenium	0.54
Styrene	0.02

Pollutant	lb/hr
Tetrachloroethylene	0.02
Toluene	0.10
1,1,1-Trichloroethane	0.01
Vinyl Acetate	0.01
Xylenes	0.02
Sulfuric Acid	5.82

8. SN-01 (boiler) is subject to 40 CFR, Part 60, Subpart A, General Provisions and 40 CFR, Part 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators due to a heat input capacity greater than 250 million British Thermal Units per hour (MMBTU/hr) and installation after August 17, 1971. 40 CFR, Part 60, Subpart D is provided as Appendix A. Applicable provisions of Subpart D, for the coal and TDF firing scenario, include, but are not limited to:

a. Pursuant to 40 CFR 60.42(a)(1), PM emissions shall not exceed 0.1 lb/MMBtu.
b. Pursuant to 40 CFR 60.42(a)(2), opacity shall not exceed 20%, except for one six-minute period per hour of not more than 27 percent opacity.
c. Pursuant to 40 CFR 60.43(a)(2), SO_2 emissions shall not exceed 1.2 lb/MMBtu.
d. Pursuant to 40 CFR 60.44(a)(3), NOx emissions shall not exceed 0.7 lb/MMBtu.
e. Pursuant to 40 CFR 60.45(a), the permittee shall install, calibrate and maintain a CEMS for NO_x, SO_2, opacity, and carbon dioxide (CO_2). According to 60.45(b)(3), Flint Creek is not required by 40 CFR Part 60, Subpart D to monitor (CEMS) for NO_X due to the actual NO_X emissions being demonstrated to be less than 70% of the NSPS standard (0.70 lbMMBtu) during the initial performance test.
f. Pursuant to 40 CFR 60.45(g)(1), excess opacity emissions are defined as any six minute period during which the average opacity emissions exceed 20%, except for one 6 minute average per hour of up to 27 percent opacity.
g. Pursuant to 40 CFR 60.45(g)(2), excess SO_2 emissions are defined as any three hour period during which the average emissions (arithmetic average of three contiguous one hour periods) of SO_2 as measured by a CEMS exceed the applicable standard under 40 CFR 60.43 (item c).
h. Pursuant to 40 CFR 60.45(g)(3), excess NO_x emissions are defined as any three hour period during which the average emissions (arithmetic average of three contiguous one hour periods) of NO_x as measured by a CEMS exceed the applicable standard under 40 CFR 60.44 (item d). According to 60.45(b)(3), Flint Creek is not required by 40 CFR Part 60, Subpart D to monitor (CEMS) for NO_X due to the actual NO_X emissions being demonstrated to be less than 70% of the NSPS standard (0.70 lbMMBtu) during the initial performance test.
i. Pursuant to 40 CFR 60.45(g), excess emission and monitoring system performance reports shall be submitted to the ADPCE for every calendar quarter. Quarterly

reports shall be postmarked by the 30th day following the end of the calendar quarter. Excess emissions are defined in 40 CFR 60.45(g). Due to the facility having demonstrated that actual NO_X emissions are less than 70% of the federal standard (0.7 lb/MMBtu), quarterly excess NO_X emission reports are not required.

j. Pursuant to 40 CFR 60.46(a), the permittee shall conduct an initial compliance test for PM and pursuant to 40 CFR 60.46(b)(2) testing shall be conducted using EPA reference method 5. (A separate test under this scenario is not required. This requirement refers to the original coal firing compliance test conducted June 19, 1979).

[§19.304 of Regulation 19, and 40 CFR 60.40]

9. The permittee shall maintain records which demonstrate compliance with the hourly SO_2 emission limit set in Specific Condition 6 and may be used by the Department for enforcement purposes. Compliance shall be determined as the average emissions (arithmetic average of three contiguous one hour periods) of SO_2 as measured by a CEMS and converted to pounds per hour using corresponding average (arithmetic average of three contiguous one hour periods) stack gas flow rates. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

10. The permittee shall maintain records which demonstrate compliance with the hourly NO_x emission limit set in Specific Condition 6 and may be used by the Department for enforcement purposes. Compliance shall be determined as the average emissions (arithmetic average of three contiguous one hour periods) of NO_x as measured by a CEMS and converted to pounds per hour using corresponding average (arithmetic average of three contiguous one hour periods) stack gas flow rates. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

11. The permittee shall test SN-01 for arsenic and lead while operating under Scenario 2: Coal and Tire Derived Fuel (TDF) Co-Firing and while operating at 90% or greater capacity. This testing shall be conducted during the next scheduled occurrence of burning tire derived fuel (TDF). These tests shall be performed using the test methods specified in the following table or other methods as approved by ADEQ, and shall be conducted in accordance with Plantwide Condition #3. [§18.1002 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	EPA Reference Method
Arsenic	108
Lead	12

SCENARIO 3: LEACHATE INJECTION WHILE COAL FIRING SPECIFIC CONDITIONS

12. The facility shall only burn coal while injecting leachate into the boiler. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

13. The permittee shall not exceed a leachate injection rate of 50 gpm and 72,000 gal in any consecutive 24 hour period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

14. The permittee shall maintain daily records of leachate throughput to demonstrate compliance with the leachate injection rate set in Specific Condition #13. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

15. The permittee shall not exceed the emission rates set forth in the following table for SN-01, when operating under Scenario 3: Leachate Injection while Coal Firing. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr
PM_{10}	778.4
SO_2	7,588.8
VOC	24.7
CO	821.3
NO_x	4,426.8
Lead	0.07

16. The permittee shall not exceed the emission rates set forth in the following table for SN-01, when operating under Scenario 3: Leachate Injection while Coal Firing. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr
PM	778.4
Acetaldehyde	0.24
Acetophenone	0.01
Acrolein	0.12

Pollutant	lb/hr
Antimony	0.01
Arsenic	0.17
Benzene	0.54
Benzyl Chloride	0.29
Beryllium	0.01
Bis(2-ethylhexyl)phthalate (DEHP)	0.03
Bromoform	0.02
Cadmium	0.03
Carbon Disulfide	0.06
2-Chloroacetophenone	0.01
Chlorobenzene	0.01
Chloroform	0.03
Chromium	0.04
Chromium VI	0.04
Cobalt	0.05
Cumene	0.01
Cyanide	1.03
2,4-Dinitrotoluene	0.01
Dimethyl Sulfate	0.02
Ethyl Benzene	0.04
Ethyl Chloride	0.02
Ethylene Dichloride	0.02
Ethylene Dibromide	0.01
Formaldehyde	0.10
Hexane	0.03
Hydrogen Chloride	43.35
Hydrogen Fluoride	61.02

Pollutant	lb/hr
Isophorone	0.24
Manganese	0.21
Mercury	0.04
Methyl Bromide	0.07
Methyl Chloride	0.22
Methyl Ethyl Ketone	0.17
Methyl Hydrazine	0.07
Methyl Methacrylate	0.01
Methyl Tert Butyl Ether	0.02
Methylene Chloride	0.12
Nickel	0.12
Phenol	0.16
Polycyclic Organic Matter	0.02
Polynuclear Aromatic Hydrocarbons	0.02
Propionaldehyde	0.16
Selenium	0.54
Styrene	0.02
Tetrachloroethylene	0.02
Toluene	0.10
1,1,1-Trichloroethane	0.01
Vinyl Acetate	0.01
Xylenes	0.02
Sulfuric Acid	5.82

17. SN-01 (boiler) is subject to 40 CFR, Part 60, Subpart A, General Provisions and 40 CFR, Part 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators due to a heat input capacity greater than 250 million British Thermal Units per hour (MMBtu/hr) and installation after August 17, 1971. 40 CFR, Part 60, Subpart D is

provided as Appendix A. Applicable provisions of Subpart D for the coal firing scenario, include, but are not limited to:

b. Pursuant to 40 CFR 60.42(a)(1), PM emissions shall not exceed 0.1 lb/MMBtu.
b. Pursuant to 40 CFR 60.42(a)(2), opacity shall not exceed 20%, except for one six-minute period per hour of not more than 27 percent opacity.
c. Pursuant to 40 CFR 60.43(a)(2), SO_2 emissions shall not exceed 1.2 lb/MMBtu.
d. Pursuant to 40 CFR 60.44(a)(3), NO_x emissions shall not exceed 0.7 lb/MMBtu.
e. Pursuant to 40 CFR 60.45(a), the permittee shall install, calibrate and maintain Continuous Emissions Monitoring Systems (CEMS) for NO_x, SO_2, opacity, and carbon dioxide (CO_2). According to 60.45(b)(3), Flint Creek is not required by 40 CFR Part 60, Subpart D to monitor (CEMS) for NO_X due to the actual NO_X emissions being demonstrated to be less than 70% of the NSPS standard (0.70 lbMMBtu) during the initial performance test.
f. Pursuant to 40 CFR 60.45(g)(1), excess opacity emissions are defined as any six minute period during which the average opacity emissions exceed 20%, except for one 6- minute average per hour of up to 27 percent opacity.
g. Pursuant to 40 CFR 60.45(g)(2), excess SO_2 emissions are defined as any three hour period during which the average emissions (arithmetic average of three contiguous one hour periods) of SO_2 as measured by a CEMS exceed the applicable standard under 60.43 (item c).
h. Pursuant to 40 CFR 60.45(g)(3), excess NO_x emissions are defined as any three hour period during which the average emissions (arithmetic average of three contiguous one hour periods) of NO_x as measured by a CEMS exceed the applicable standard under 60.44 (item d). According to 60.45(b)(3), Flint Creek is not required by 40 CFR Part 60, Subpart D to monitor (CEMS) for NO_X due to the actual NO_X emissions being demonstrated to be less than 70% of the NSPS standard (0.70 lbMMBtu) during the initial performance test.
i. Pursuant to 40 CFR 60.45(g), excess emission and monitoring system performance reports shall be submitted to the ADEQ for every calendar quarter. Quarterly reports shall be postmarked by the 30th day following the end of the calendar quarter. Excess emissions are defined in 60.45(g). Due to the facility having demonstrated that actual NO_X emissions are less than 70% of the federal standard (0.7 lb/MMBtu), quarterly excess NO_X emission reports are not required.
j. Pursuant to 40 CFR 60.46(a), the permittee shall conduct an initial compliance test for PM and pursuant to 40 CFR 60.46(b)(2) testing shall be conducted using EPA reference method 5. (Testing was conducted June 19, 1979).

[§19.304 of Regulation 19, and 40 CFR 60, Subpart D]

18. The permittee shall maintain records which demonstrate compliance with the hourly SO_2 emission limit set in Specific Condition #15 and may be used by the Department for enforcement purposes. Compliance shall be determined as the average emissions (arithmetic average of three contiguous one hour periods) of SO_2 as measured by a CEMS and converted to pounds per hour using corresponding average (arithmetic average of three contiguous one hour periods) stack gas flow rates. These records shall

be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

19. The permittee shall maintain records which demonstrate compliance with the hourly NO_x emission limit set in Specific Condition #15 and may be used by the Department for enforcement purposes. Compliance shall be determined as the average emissions (arithmetic average of three contiguous one hour periods) of NO_x as measured by a CEMS and converted to pounds per hour using corresponding average (arithmetic average of three contiguous one hour periods) stack gas flow rates. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

OTHER SPECIFIC CONDITIONS

These conditions apply to the boiler (SN-01) during all operating scenarios.

20. In accordance with the administrator's (EPA Region VI) determination (see Appendix D), fuel oil and coal co-firing shall occur in accordance with the following limitations. If the permittee fails to comply with the limitations, the determination of "representative" conditions is no longer valid and the permittee shall conduct compliance testing for PM in accordance with 40 CFR 60.46. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

    a. Co-firing fuel oil to start up or shut down pulverizer mills shall be used for a duration not to exceed the time which allows for coal ignition and boiler flame stabilization.

    b. The permittee has stated that fuel oil is co-fired only once every 7 to 8 years for flame stabilization when coal is frozen. If this scenario occurs once or more per year for three consecutive years, the permittee shall submit information regarding this scenario to the administrator for reevaluation of applicability of 40 CFR, Part 60, subpart D and may be required to conduct compliance testing as required under 40 CFR 60.46.

    c. The permittee has stated that the fuel oil storage tank is emptied once every 15 years for maintenance. If this scenario occurs once or more per year for three consecutive years, the permittee shall submit information regarding this scenario to the administrator for reevaluation of applicability of 40 CFR, Part 60, subpart D and may be required to conduct compliance testing as required under 40 CFR 60.46.

21. EPA Region VI has determined, based on the information dated August 22, 1995, that firing fuel oil to prevent boiler tube failure is a mode of boiler shut down. Pursuant to the administrator's (EPA Region VI) determination, fuel oil firing shall occur in accordance

with the following limitations. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

a. Fuel oil firing shall only occur in the event that it is necessary to prevent boiler tube failure in extreme cold weather if the boiler (SN-01) is shut down.

b. The permittee shall not generate steam to produce electricity while firing only fuel oil in this scenario. This scenario is considered a mode of boiler shut down.

c. The permittee shall maintain records sufficient to document the time period when fuel oil is fired to prevent boiler tube failure, the hourly fuel oil firing rate, and the heat input to the boiler (SN-01). These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision 7.

22. The permittee may burn No. 2 Fuel Oil at SN-01 during startup, shutdown, and malfunction. Additionally, the permittee may burn No. 2 Fuel Oil at SN-01 during periodic boiler chemical cleaning and for fuel oil ignitor system testing and maintenance activities. For all other No. 2 Fuel Oil burning activities not already included in this permit (i.e., fuel flow problems), the permittee shall submit a request to EPA for a determination regarding the applicability of NSPS Subpart D limits and testing requirements during the coal and fuel oil co-firing and fuel oil only firing scenarios. The permittee may burn No. 2 Fuel Oil for all other No. 2 Fuel Oil burning activities not already included in this permit, i.e., "fuel flow problems", until the permittee receives a written determination from EPA. The permittee submitted a request for determination on October 27, 2005. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

23. The permittee shall not exceed the annual emission rates, set forth in the following table. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Pollutant	tpy
PM_{10}	3,068.4
SO_2	29,915.0
VOC	97.3
CO	3,241.8
NO_x	17,450.4
Lead	0.25

24. The permittee shall not exceed the annual emission rates, set forth in the following table. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	tpy
PM	3,068.4
Acetaldehyde	0.93
Acetophenone	0.03
Acrolein	0.48
Antimony	0.03
Arsenic	0.67
Benzene	2.11
Benzyl Chloride	1.14
Beryllium	0.04
Bis(2-ethylhexyl)phthalate (DEHP)	0.12
Bromoform	0.07
Cadmium	0.09
Carbon Disulfide	0.22
2-Chloroacetophenone	0.02
Chlorobenzene	0.04
Chloroform	0.10
Chromium	0.43
Chromium VI	0.13
Cobalt	0.17
Cumene	0.01
Cyanide	4.06
2,4-Dinitrotoluene	0.01
Dimethyl Sulfate	0.08
Ethyl Benzene	0.16
Ethyl Chloride	0.07
Ethylene Dichloride	0.07

Pollutant	tpy
Ethylene Dibromide	0.01
Formaldehyde	2.80
Hexane	0.11
Hydrogen Chloride	170.89
Hydrogen Fluoride	240.54
Isophorone	0.95
Manganese	0.80
Mercury	0.14
Methyl Bromide	0.26
Methyl Chloride	0.86
Methyl Ethyl Ketone	0.64
Methyl Hydrazine	0.28
Methyl Methacrylate	0.04
Methyl Tert Butyl Ether	0.06
Methylene Chloride	0.48
Nickel	0.46
Phenol	0.62
Polycyclic Organic Matter	0.06
Polynuclear Aromatic Hydrocarbons	0.06
Propionaldehyde	0.62
Selenium	2.11
Styrene	0.05
Tetrachloroethylene	0.07
Toluene	0.39
1,1,1-Trichloroethane	0.04
Vinyl Acetate	0.02
Xylenes	0.06

Pollutant	tpy
Sulfuric Acid	25.48

25. The permittee shall not exceed 20% opacity from the boiler (SN-01) as determined using a continuous opacity monitor certified in accordance with 40 CFR Part 60 Appendix B. [§19.503 of Regulation 19, and 40 CFR Part 52, Subpart E]

26. The permittee shall maintain records, using a continuous opacity monitoring system, which demonstrate compliance with the opacity emission limit set in Specific Condition #25 and may be used by the Department for enforcement purposes. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

27. The permittee shall monitor the opacity of SN-01 using a continuous opacity monitoring system. The permittee shall initiate corrective action when the measured opacity is greater than 20% for a one-hour average. Corrective actions shall include:

    a. If the ESP is operating at reduced power (<200 KVA), the transformer-rectifier (TR) set parameters will be adjusted in an attempt to optimize achievable levels.

    b. Any individual TR sets that are out-of-service or not operating at optimum power levels shall be repaired and/or adjusted as appropriate.

    c. ESP rapping procedures may be initiated and/or adjusted as necessary.

    d. Depending on the specific events found to be the cause of the opacity increase, other corrective actions will be implemented as necessary to reduce the opacity to normal operating levels.

    e. Reduce load if appropriate and deemed effective.

    The permittee shall maintain records of the measured opacity and any corrective actions taken (Appendix C). [§19.304 of Regulation 19, and 40 CFR Part 64]

28. A monitoring report shall be submitted to the Department in accordance with General Provision #7 and shall include the following per 40 CFR §64.9(a)(2):

    a. The information required under 40 CFR §70.6(a)(3)(iii);

    b. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

    c. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

d. A description of the actions taken to implement a Quality Improvement Plan (QIP), if required, during the reporting period as specified in §64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring. A QIP shall be required if the excess emissions for opacity, as reported on the Quarterly Excess Emissions Report, exceeds 5% of the unit operating time.

[§19.304 of Regulation 19, and 40 CFR Part 64]

29. The permittee shall test SN-01 for PM and PM_{10} while operating at 90% or greater capacity (based on 558 MW gross capacity of the unit). Emission results shall be extrapolated to correlate with 100% of the permitted capacity to determine compliance. The PM test shall be performed using EPA Reference Methods 5 and 202. The PM_{10} test shall be performed using either EPA Reference Methods 201A and 202 or 5 and 202. These tests shall be conducted in accordance with Plantwide Condition #3. EPA Reference Method 5 shall be used to demonstrate compliance with Specific Conditions #3a, #8a, and #17a. EPA Reference Methods 5 and 202 shall be used to demonstrate compliance with Specific Conditions #7, #16, and #24. EPA Reference Methods 201A and 202 or 5 and 202 shall be used to demonstrate compliance with Specific Conditions #6, #15 and #23. By using Methods 5 and 202 for PM_{10}, the permittee will assume all collected particulate is PM_{10}.

This testing shall be conducted within 90 days of permit issuance. Subsequent tests shall be performed every five years and when the annual weighted average sulfur content or annual weighted average ash content changes such that:

$$\left[\left((\text{New Sulfur \%} - \text{Tested Sulfur \%}) \times 822.2\right) + \left((\text{New Ash \%} - \text{Tested Ash \%}) \times 32.9\right)\right] > \left[\left(\text{Permitted PM limit, lb/hr}\right) - \left(\text{Tested PM rate, lb/hr}\right)\right]$$

or whenever:

$$\left[\left((\text{New Sulfur \%} - \text{Tested Sulfur \%}) \times 822.2\right) + \left((\text{New Ash \%} - \text{Tested Ash \%}) \times 22.2\right)\right] > \left[\left(\text{Permitted } PM_{10} \text{ limit, lb/hr}\right) - \left(\text{Tested } PM_{10} \text{ rate, lb/hr}\right)\right]$$

The annual weighted average coal quality analysis shall be used in the above equations to determine whether re-testing for PM and PM_{10} is necessary, and the calculated results shall be maintained onsite. These calculations shall be performed once per calendar year using the annual weighted average coal analysis data from the preceding calendar year. The calculations shall be completed prior to the end of the first quarter. See Appendix E for derivation of the above conditional equations. Any required re-testing due to sulfur content or ash content changes shall be conducted within 180 days of detecting the change based on the annual calculations referenced above. Documentation of the coal analyses from each new shipment of coal shall be maintained onsite. [§19.702 of Regulation 19, 40 CFR Part 52, Subpart E, §19.304 of Regulation 19, and 40 CFR Part 64]

30. The permittee shall test SN-01 for CO. This testing shall be conducted within 180 days of permit issuance and every 5 years thereafter. These tests shall be conducted at 90% or greater capacity (based on 558 MW gross capacity of the unit) using EPA Reference Method 10. These tests shall be conducted in accordance with Plantwide Condition #3. [§19.702 of Regulation 19 and 40 CFR Part 52, Subpart E]

31. The permittee shall not exceed 29,915.0 tpy of SO_2 emissions for any consecutive twelve month period. [§19.501 of Regulation 19, and 40 CFR Part 52, Subpart E]

32. The permittee shall maintain records, using CEMS for SO_2, which demonstrate compliance with the limit set in Specific Condition #31 and may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. A 12-month rolling total and each individual month's data shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

33. The permittee shall not exceed 17,450.4 tpy NO_x emissions for any consecutive twelve month period. [§19.501 of Regulation 19, and 40 CFR Part 52, Subpart E]

34. The permittee shall maintain records, using a CEMS for NO_x, which demonstrate compliance with the limit set in Specific Condition #33 and may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. A 12-month rolling total and each individual month's data shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

35. The permittee shall maintain a CEMS for SO_2, NO_x, volumetric flow, and CO_2 in accordance with the specifications in Appendix A. This CEMS shall comply with the Air Division's "Continuous Emission Monitoring Systems Conditions, as revised August 2004". A copy is provided in Appendix B. [§19.304 of Regulation 19, and 40 CFR 75]

36. The permittee shall submit the required quarterly monitoring reports to EPA headquarters. [§19.304 of Regulation 19 and 40 CFR 75]

37. Relative accuracy tests will be performed following the requirements under 40 CFR 75. This relative accuracy test will meet the requirements under 40 CFR Part 60, Subpart D. [§19.304 of Regulation 19 and 40 CFR 75]

38. The permittee shall determine and record the heat input to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in Appendix F of 40 CFR Part 75. This calculation will meet the requirements under 40 CFR, Part 60, Subpart D. [§19.304 of Regulation 19 and 40 CFR 75.10(c)]

39. The facility may evaporate non-hazardous boiler and condenser cleaning wastes generated as the result of the periodic cleaning of the boiler and/or condenser. The

evaporation shall last less than 146 hours, in the aggregate, during a consecutive 12-month period.

The facility must submit a written request to perform this action to the Department thirty (30) days prior to the evaporation procedure. The written request shall be sent to the address in General Provision 7. The request shall include a description of how the cleaning waste is generated and evaporated, how much cleaning waste will be evaporated, and Material Safety Data Sheets for the chemicals that are utilized in the cleaning process. The facility must have permission from the Department before commencing the evaporation.
[A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

40. In accordance with General Provision #17, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26, §26.701(I)(1)]

SN-02
Fly Ash Silo

Source Description

Collected fly ash is pneumatically conveyed to a fly ash silo and is shipped offsite for reuse or to the fly ash landfill. Particulate emissions from the fly ash silo are controlled by a baghouse.

Specific Conditions

41. The permittee shall not exceed the emission rates set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§19.501 of Regulation 19 et seq and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.1

42. The permittee shall not exceed the emission rates set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§18.801 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	0.1	0.1

43. The permittee shall not exceed 5% opacity at the fly ash silo baghouse vents as measured by EPA Reference Method 9. Opacity (fugitive emissions) originating from other areas of the ash silo (including but not limited to the off-loading chutes) shall be minimized by adherence to Plantwide Condition #5. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

44. The permittee shall conduct weekly observations of the opacity from SN-02 and keep a record of these observations. If opacity is observed from the baghouse vents, Method 9 shall be used for determining opacity. Visible emission observations shall be used for any fugitive emissions on the remainder of the ash silo. If, during the weekly observation, opacity from the vents or fugitive visible emissions are observed, the permittee shall take immediate action to identify and correct the cause of the opacity or visible emissions. After corrective action has been taken, the permittee shall conduct another observation (Method 9 or visible emission observation, as appropriate) to confirm that visible emissions are no longer present. If visible emissions are still present following the corrective action, the permittee shall document that the baghouse vent

emissions do not exceed 5% opacity and that visible emissions do not cause a nuisance beyond the property boundary. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. The permittee shall maintain the following records which shall be kept on site and shall be made available to Department personnel upon request: [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

1. The date and time of the observation.
2. If opacity or visible emissions were detected.
3. If opacity or visible emissions were detected, the cause of the emissions, the corrective action taken, and if the visible emissions were present after the corrective action was taken.
4. If visible emissions were present following the corrective action, document that the visible emissions do not exceed 5% opacity from the vents and do not cause a nuisance beyond the property boundary.
5. The name of the person conducting the observations.

SN-03
Coal Car Dumper

Source Description

Coal is supplied via railcar and dumped into a hopper. Emissions from the coal car dumper are controlled by an enclosure and use of water spray. The coal car dumper was installed in 1978.

Although the particulate emission rate is very low, the permitting authority understands that instantaneous visible emissions may occur due to the wind if a train is occupying the Coal Car Dumper and the doors cannot be closed. Therefore, the opacity limit for this source is 20%.

Specific Conditions

45. The permittee shall not exceed the emission rates set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.1

46. The permittee shall not exceed the emission rates set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	0.3	0.2

47. The permittee shall conduct weekly visible emission observations of the opacity from SN-03 and keep a record of these observations. If, during the weekly observation, visible emissions are observed, the permittee shall take immediate action to identify and correct the cause of the visible emissions. The permitting authority understands that instantaneous visible emissions may occur due to the wind if a train is occupying the Coal Car Dumper and the doors cannot be closed. Such instantaneous visible emissions do not trigger corrective action but will be noted below. After corrective action has been taken, the permittee shall conduct another visible emission observation of the opacity to confirm that visible emissions are no longer present. If visible emissions are still present following the corrective action, the permittee shall document that visible emissions do not cause a nuisance beyond the property boundary. Under normal conditions, opacity

less than or equal to 5% shall not be considered a nuisance. The permittee shall maintain the following records which shall be kept on site and shall be made available to Department personnel upon request: [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

1. The date and time of the observation.
2. If visible emissions were detected.
3. If visible emissions were detected, the cause of the visible emissions, the corrective action taken, and if the visible emissions were present after the corrective action was taken.
4. If visible emissions were present following the corrective action, document that the visible emissions do not cause a nuisance beyond the property boundary.
5. The name of the person conducting the opacity observations.

48. The permittee shall utilize a water spray as necessary to minimize emissions at the coal car dumper (SN-03), except when the ambient temperature is below 40 degrees F or while it is raining. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-04
Coal Bunker

Source Description

Coal is transferred from the coal bunker conveyor into the coal tripper house and then into the coal bunker silos (SN-04). Emissions from the coal bunker are controlled by two baghouses. The coal bunker was installed in 1978.

Specific Conditions

49. The permittee shall not exceed the emission set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.1

50. The permittee shall not exceed the emission set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	0.1	0.1

51. The permittee shall not exceed 5% opacity at the coal bunker baghouse vents (SN-04) as measured by EPA Reference Method 9. [§18.501 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

52. The permittee shall conduct weekly observations of the opacity from SN-04 and keep a record of these observations. If visible emissions are observed, the permittee shall take immediate action to identify and correct the cause of the visible emissions. After corrective action has been taken, the permittee shall conduct another observation of the opacity from the source in question to confirm that visible emissions are no longer present. If visible emissions are still present following the corrective action, the permittee shall document that the bag house vent emissions do not exceed 5%. The permittee shall maintain the following records which shall be kept on site and shall be made available to Department personnel upon request: [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

    1. The date and time of the observation.

2. If visible emissions were detected.
3. If visible emissions were detected, the cause of the visible emissions, the corrective action taken, and if the visible emissions were present after the corrective action was taken.
4. If visible emissions were present following the corrective action, document that the visible emissions do not exceed 5%.
5. The name of the person conducting the opacity observations.

SN-05
Coal Bunker Conveyor

Source Description

Coal is transferred from the coal bunker conveyor (SN-05) into the coal tripper house and then into the coal bunker silos. Emissions from the coal bunker conveyor are controlled by use of an enclosure. The coal bunker conveyor was installed in 1978.

Specific Conditions

53. The permittee shall not exceed the emission rates set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.2

54. The permittee shall not exceed the emission rates set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	0.1	0.3

55. Emissions from the coal bunker conveyor (SN-05) shall be minimized by adherence to Plantwide Condition #5. [§19.503 of Regulation 19, and 40 CFR Part 52, Subpart E]

56. The permittee shall conduct weekly visual emission observations of the opacity from SN-05 and keep a record of these observations. If, during the weekly observation, visible emissions are observed, the permittee shall take immediate action to identify and correct the cause of the visible emissions. After corrective action has been taken, the permittee shall conduct another visual emission observation of the opacity to confirm that visible emissions are no longer present. If visible emissions are still present following the corrective action, the permittee shall document that visible emissions do not cause a nuisance beyond the property boundary. Under normal conditions, opacity less than or equal to 5% shall not be considered a nuisance. The permittee shall maintain the following records which shall be kept on site and shall be made available to Department personnel upon request: [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

1. The date and time of the observation.
2. If visible emissions were detected.
3. If visible emissions were detected, the cause of the visible emissions, the corrective action taken, and if the visible emissions were present after the corrective action was taken.
4. If visible emissions were present following the corrective action, document that the visible emissions do not cause a nuisance beyond the property boundary.
5. The name of the person conducting the opacity observation.

SN-06
Coal Transfer House

Source Description

Coal from the hopper dumps onto an enclosed conveyor system and is transported to the coal transfer house (SN-06). At the coal transfer house, the coal can either be dropped onto the conveyor which dumps coal onto a coal pile or the coal can be dropped onto the coal bunker conveyor. Emissions from the coal transfer house are controlled by use of an enclosure and use of water sprays.

Specific Conditions

57. The permittee shall not exceed the emission rates, at source SN-06, set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.1

58. The permittee shall not exceed the emission rates, at source SN-06, set forth in the following table. Compliance with Plantwide Condition #7 may represent compliance with the source's applicable requirements. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	0.3	0.2

59. Emissions from the coal transfer house (SN-06) shall be minimized by adherence to Plantwide Condition #5. [§19.503 of Regulation 19, and 40 CFR Part 52, Subpart E]

60. The permittee shall conduct weekly visual emission observations of the opacity from SN-06 and keep a record of these observations. If, during the weekly observation, visible emissions are observed, the permittee shall take immediate action to identify and correct the cause of the visible emissions. After corrective action has been taken, the permittee shall conduct another visual emission observation of the opacity to confirm that visible emissions are no longer present. If visible emissions are still present following the corrective action, the permittee shall document that visible emissions do not cause a nuisance beyond the property boundary. Under normal conditions, opacity less than or equal to 5% shall not be considered a nuisance. The permittee shall maintain the

following records which shall be kept on site and shall be made available to Department personnel upon request: [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

1. The date and time of the observation.
2. If visible emissions were detected.
3. If visible emissions were detected, the cause of the visible emissions, the corrective action taken, and if the visible emissions were present after the corrective action was taken.
4. If visible emissions were present following the corrective action, document that the visible emissions do not cause a nuisance beyond the property boundary.
5. The name of the person conducting the opacity observations.

61. The permittee shall utilize a water spray as necessary to minimize emissions at the coal transfer house (SN-06) except when the ambient temperature is below 40 degrees F or while it is raining. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-07
Coal Storage Pile

Source Description

Coal from the hopper dumps onto an enclosed conveyor system and is transported to the coal transfer house. At the coal transfer house, the coal can either be dropped onto the conveyor which dumps coal onto a coal pile (SN-07) or the coal can be dropped onto the coal bunker conveyor. Coal can be reclaimed from the coal pile using hoppers located underneath the coal pile and conveying the coal back to the coal transfer house.

Specific Conditions

62. The permittee shall not exceed the emission rates, at source SN-07, set forth in the following table. Compliance with Plantwide Condition #5 represents compliance with the rates specified for this requirement. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	16.9	15.5

63. The permittee shall not exceed the emission rates, at source SN-07, set forth in the following table. Compliance with Plantwide Condition #5 represents compliance with the rates specified for this requirement. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	39.1	54.3

64. The permittee shall not operate in a manner such that fugitive emissions from the storage pile, pile operations (such as operation of mobile equipment upon the storage pile), and haul road would cause a nuisance off-site. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

65. The permittee shall utilize a water spray as necessary to minimize emissions at the coal storage pile (SN-07). Water treatment shall not be required when the ambient temperature is below 40°F or while it is raining. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-08
Ash Landfill

Source Description

Fly ash resulting from the coal combustion process is collected by two electrostatic precipitators. The fly ash collected from the electrostatic precipitators is pneumatically conveyed to a fly ash silo and is shipped offsite for reuse or to the fly ash landfill (SN-08).

Specific Conditions

66. The permittee shall not exceed the emission rates, at source SN-08, set forth in the following table. Compliance with Plantwide Condition #5 represents compliance with the rates specified for this requirement. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	1.2	0.7

67. The permittee shall not exceed the emission rates, at source SN-08, set forth in the following table. Compliance with Plantwide Condition #5 represents compliance with the rates specified for this requirement. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	3.1	4.3

68. The permittee shall not operate in a manner such that fugitive emissions from the ash landfill, landfill operations (such as operation of mobile equipment upon the landfill), and haul road would cause a nuisance off-site. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

69. The permittee shall utilize a water spray as necessary to minimize emissions at the ash landfill (SN-08). Water treatment shall not be required when the ambient temperature is below 40°F or while it is raining. A thermometer shall be maintained on site. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-14, 15, 18
Storage Tanks

Source Description

Additional emission points include three liquid fuel storage tanks for diesel fuel (SN-14), gasoline (SN-15), and fuel oil (SN-18). The diesel fuel tank has a capacity of 15,000 gallons and a throughput of 200,000 gallons per year. The gasoline tank has a capacity of 1,500 gallons and a potential throughput of 10,000 gallons. The fuel oil tank has a capacity of 921,060 gallons and a potential throughput of 6,662,560 gallons.

Specific Conditions

70. The permittee shall not exceed the emission rates, at sources SN-14, SN-15, and SN-18, set forth in the following table. [§19.501 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E]

Source No.	Pollutant	lb/hr	tpy
SN-14	VOC	0.5	0.1
SN-15	VOC	18.3	0.9
SN-18	VOC	0.7	0.3

71. The permittee shall not exceed a throughput of 200,000 gallons of diesel fuel at SN-14 during any consecutive 12-month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

72. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Condition #71 and may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. A 12-month rolling total and each individual month's data shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

73. The permittee shall not exceed a throughput of 10,000 gallons of gasoline at SN-15 during any consecutive 12-month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

74. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Condition #73 and may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. A 12-month rolling total and each

individual month's data shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

75. The permittee shall not exceed a throughput of 6,662,560 gallons of fuel oil at SN-18 during any consecutive 12-month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

76. The permittee shall maintain records which demonstrate compliance with the limit set in Specific Condition #75 and may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. A 12-month rolling total and each individual month's data shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

American Electric Power - Flint Creek Power Plant will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19, §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19, §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) days after completing the testing. [Regulation 19, §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

4. The permittee must provide:

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

    [Regulation 19, §19.702 and/or Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19, §19.303 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

7. The annual throughput of coal at the facility shall not exceed 3,237,560 tons of coal during any consecutive 12-month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR 70.6]

8. The permittee shall maintain monthly records which demonstrate compliance with the limit set in Plantwide Condition #7. These records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. A 12-month rolling total and each individual month's data shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

9. The annual throughput of TDF at the facility shall not exceed 7,300 tons during any consecutive 12-month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR 70.6]

10. The permittee shall maintain monthly records which demonstrate compliance with the limit set in Plantwide Condition #9. These records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. A 12-month rolling total and each individual month's data shall be submitted in accordance with General Provision 7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

11. The permittee shall completely enclose by fence all areas in the model that were excluded from the ambient air with the exception of the shoreline. The fence shall be installed within 180 days of issuance of Permit #0276-AOP-R3. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Acid Rain (Title IV)

12. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. A copy of the facility's Acid Rain Permit is attached in an appendix to this Title V permit. [Regulation 26, §26.701 and 40 CFR 70.6(a)(4)]

CAIR

13. The permittee shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of 40 CFR part 96. The permittee shall comply with the NO_x emission requirements established under CAIR. The Permittee shall report and maintain the records required by subpart HHHH of 40 CFR part 96. A copy of the CAIR

permit is attached to this Title V permit. [Regulation No. 19 §19.1401 and 40 CFR Part 52, Subpart E]

Title VI Provisions

14. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]

    a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
    b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
    c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
    d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

15. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
    b. 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.
    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
    d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC like appliance" as defined at §82.152)
    e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
    f. 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.

16. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.

17. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable

requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

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.

18. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G.

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated (*insert application date*).

Description	Category
Diesel Fire Pump 2.97 MMBTU/hr (SN-13)	A-1
Portable Baghouse Diesel Engine (1 unit – 0.91 MMBtu/hr)	A-1
Vacuum Trucks Diesel Engines (2 units – 1.86 MMBtu/hr total)	A-1
Water Pumps Diesel Engines (2 units – 1.46 MMBtu/hr total)	A-1
560 Gallon Kerosene Tank (SN-16)	A-3
1,000 Gallon Used Oil Tank (SN-17)	A-3
500 Gallon Used Oil Tank (SN-19)	A-3
Emergency Generator (SN-12)	A-12
Gasoline Refueling Emissions (SN-10)	A-13
Diesel Refueling Emissions (SN-11 and diesel refueling for maintenance activities)	A-13
Sandblast Rigs Diesel Engines (5 units – 7.78 MMBtu/hr total)	A-13
Maintenance Activities (Portable Baghouse and Vacuum Trucks used twice a year)	A-13
Placing residual fire fighter training refuse and small amounts of soil and/or water contaminated with diesel fuel and/or oil onto the coal pile	A-13
Use of up to 10,000 gallons per 12-month period of Soil Sement on the coal storage pile to reduce dust	A-13
Solvent use for equipment maintenance that is not related to the sources' primary business activity (SN-09)	B-14

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26, §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26, §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses performed;
    c. The company or entity performing the analyses;
    d. The analytical techniques or methods used;
    e. The results of such analyses; and
    f. The operating conditions existing at the time of sampling or measurement.

    [40 CFR 70.6(a)(3)(ii)(A) and Regulation 26, §26.701(C)(2)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26, §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due within thirty (30) days of the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below:

    Arkansas Department of Environmental Quality
    Air Division
    ATTN: Compliance Inspector Supervisor
    5301 Northshore Drive
    North Little Rock, AR 72118-5317

    [40 C.F.R. 70.6(a)(3)(iii)(A) and Regulation 26, §26.701(C)(3)(a)]

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

    a. For all upset conditions (as defined in Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

        i. The facility name and location;
        ii. The process unit or emission source deviating from the permit limit;
        iii. The permit limit, including the identification of pollutants, from which deviation occurs;
        iv. The date and time the deviation started;
        v. The duration of the deviation;
        vi. The average emissions during the deviation;
        vii. The probable cause of such deviations;
        viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
        ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19, §19.601 and §19.602, Regulation 26, §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26, §26.701(E), and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26, §26.701(F)(1)]

11. 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 to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26, §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26, §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26, §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26, §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26, §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26, §26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26, §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26, §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26, §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26, §26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually within 30 days following the last day of the anniversary month of the initial Title V permit. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26, §26.703(E)(3)]

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation 26, §26.704(C)]

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act; or
d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:

a. Such an extension does not violate a federal requirement;
b. The permittee demonstrates the need for the extension; and
c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Regulation 18, §18.314(A), Regulation 19, §19.416(A), Regulation 26, §26.1013(A), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:

    a. Such a request does not violate a federal requirement;
    b. Such a request is temporary in nature;
    c. Such a request will not result in a condition of air pollution;
    d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
    e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
    f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Regulation 18, §18.314(B), Regulation 19, §19.416(B), Regulation 26, §26.1013(B), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:

    a. The request does not violate a federal requirement;
    b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
    c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Regulation 18, §18.314(C), Regulation 19, §19.416(C), Regulation 26, §26.1013(C), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

Appendix A

e-CFR Data is current as of October 15, 2009

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Browse Previous | Browse Next

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971

Source: 72 FR 32717, June 13, 2007, unless otherwise noted.

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts (MW) heat input rate (250 million British thermal units per hour (MMBtu/hr)).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 MW (250 MMBtu/hr).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility covered under subpart Da is not covered under this subpart.

§ 60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference, see §60.17).

Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm,

gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

Fossil fuel and wood residue-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

Fossil-fuel-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

Wood residue means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

§ 60.42 Standard for particulate matter (PM).

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

(1) Contain PM in excess of 43 nanograms per joule (ng/J) heat input (0.10 lb/MMBtu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35 percent opacity, except that a maximum or 42 percent opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32 percent opacity, except that a maximum of 39 percent opacity shall be permitted for not more than six minutes in any hour.

(c) As an alternate to meeting the requirements of paragraph (a) of this section, an owner or operator that elects to install, calibrate, maintain, and operate a continuous emissions monitoring systems (CEMS) for measuring PM emissions can petition the Administrator (in writing) to comply with §60.42Da (a) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.43Da(a) of subpart Da of this part.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009]

§ 60.43 Standard for sulfur dioxide (SO_2).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of:

(1) 340 ng/J heat input (0.80 lb/MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 ng/J heat input (1.2 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y\,(340) + z\,(520)}{(y + z)}$$

Where:

$PS_{SO}2$= Prorated standard for $S_{O2}$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.43Da(i)(3) of subpart Da of this part or comply with §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.43Da(i)(3) of subpart Da of this part or §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.

(e) Units 1 and 2 (as defined in appendix G of this part) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 ng/J (1.1 lb/MMBtu) combined heat input to Units 1 and 2.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009]

§ 60.44 Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO_X, expressed as NO_2in excess of:

(1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.

(2) 129 ng/J heat input (0.30 lb/MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

(3) 300 ng/J heat input (0.70 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 ng/J heat input (0.60 lb MMBtu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 ng/J heat input (0.80 lb MMBtu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c), (d), and (e) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_2} = \frac{w\,(260) + x\,(86) + y\,(130) + z\,(300)}{(w + x + y + z)}$$

Where:

PS_{NOX}= Prorated standard for $NO_X$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = Percentage of total heat input derived from lignite;

x = Percentage of total heat input derived from gaseous fossil fuel;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NO_Xdoes not apply.

(d) Except as provided under paragraph (e) of this section, cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(e) As an alternate to meeting the requirements of paragraphs (a), (b), and (d) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.44Da(e)(3) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.44Da(e)(3) of subpart Da of this part.

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a CEMS for measuring SO2emissions, NOXemissions, and either oxygen (O2) or carbon dioxide (CO2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that burns only gaseous or liquid fossil fuel (excluding residual oil) with potential SO2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO2or PM, CEMS for measuring the opacity of emissions and SO2 emissions are not required if the owner or operator monitors SO2emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2emissions is not required if the owner or operator monitors SO_2emissions by fuel sampling and analysis.

(3) Notwithstanding §60.13(b), installation of a CEMS for NO_Xmay be delayed until after the initial performance tests under §60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of $NO_X$are less than 70 percent of the applicable standards in §60.44, a CEMS for measuring NO_Xemissions is not required. If the initial performance test results show that NO_Xemissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_Xwithin one year after the date of the initial performance tests under §60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator does not install any CEMS for sulfur oxides and NO_X, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a CEMS for measuring either O_2or $CO_2$is not required.

(5) An owner or operator may petition the Administrator (in writing) to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.

(6) A CEMS for measuring the opacity of emissions is not required for a fossil fuel-fired steam generator that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (b)(6)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (b)(6) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(7) The owner or operator of an affected facility subject to an opacity standard under §60.42 and that elects to not install a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of this section, monitors PM emissions as specified under paragraph (b)(5) of this section, or monitors CO emissions as specified under paragraph (b)(6) of this section shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.42 and shall comply with either paragraphs (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.

(i) Except as provided in paragraph (b)(7)(ii) or (b)(7)(iii) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (b)(7) of this section according to the applicable schedule in paragraphs (b)(7)(i)(A) through (b)(7)(i)(D) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to

5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

(ii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance test, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (b)(7)(ii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.* , 90 seconds per 30 minute period) the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.* , 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (b)(7) of this section within 30 calendar days according to the requirements in §60.46(b)(3).

(B) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (b)(7)(ii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(c) For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in §60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(i) Except as provided under paragraph (c)(3)(ii) of this section, SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	([1])	500.
Liquid	1,000	500.
Solid	1,500	1,000.
Combinations	1,000y + 1,500z	500 (x + y) + 1,000z.

[1]Not applicable.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel;

y = Fraction of total heat input derived from liquid fossil fuel; and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the $SO_2$and NO_Xspan values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (c)(3)(i) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm. Span values that are computed under paragraph (c)(3)(ii) of this section shall be rounded off according to the applicable procedures in section 2 of appendix A to part 75 of this chapter.

(5) For a fossil-fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMS shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(1) When a CEMS for measuring $O_2$is selected, the measurement of the pollutant concentration and O_2concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$are determined under paragraph (f) of this section.

(2) When a CEMS for measuring $CO_2$is selected, the measurement of the pollutant concentration and CO_2concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(1) E = pollutant emissions, ng/J (lb/MMBtu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(3) $\%O_2$, $\%CO_2$ = O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = $2,723 \times 10^{-17}$dscm/J (10,140 dscf/MMBtu) and $F_c = 0.532 \times 10^{-17}$scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.637×10^{-7}dscm/J (9,820 dscf/MMBtu) and $F_c = 0.486 \times 10^{-7}$scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476×10^{-7}dscm/J (9,220 dscf/MMBtu) and $F_c = 0.384 \times 10^{-7}$scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347×10^{-7}dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322×10^{-7}scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338×10^{-7}scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589×10^{-7}dscm/J (9,640 dscf/MMBtu) and $F_c = 0.500 \times 10^{-7}$scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492×10^{-7}dscm/J (9,280 dscf/MMBtu) and F_c = 0.494×10^{-7}scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.659×10^{-7}dscm/J (9,900 dscf/MMBtu) and $F_c = 0.516 \times 10^{-7}$scm CO_2/J (1,920 scf CO_2/MMBtu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6} \frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5} (\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6} \frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321 \times 10^3\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2 (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see §60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see §60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

Where:

X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);

$F_i$or $(F_c)_i$= Applicable F or $F_c$factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity* . Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of §60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of §60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

(2) *Sulfur dioxide.* Excess emissions for affected facilities are defined as:

(i) For affected facilities electing not to comply with §60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43; or

(ii) For affected facilities electing to comply with §60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43. Facilities complying with the 30-day SO_2 standard shall use the most current associated SO_2 compliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part or §§60.45b and 60.47b of subpart Db of this part, as applicable.

(3) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring NO_X are defined as:

(i) For affected facilities electing not to comply with §60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44; or

(ii) For affected facilities electing to comply with §60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_X as measured by a CEMS exceed the applicable standard in §60.44. Facilities complying with the 30-day NO_X standard shall use the most current associated NO_X compliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part.

(4) *Particulate matter.* Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in §60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§60.48Da and 60.49Da of subpart Da of this part.

(h) The owner or operator of an affected facility subject to the opacity limits in §60.42 that elects to monitor emissions according to the requirements in §60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009]

§ 60.46 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the PM, SO_2, and NO_X standards in §§60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of PM, SO_2, or NO_X shall be computed for each run using the following equation:

$$E = CF_d\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where:

E = Emission rate of pollutant, ng/J (1b/million Btu);

C = Concentration of pollutant, ng/dscm (1b/dscf);

$\%O_2$= O_2 concentration, percent dry basis; and

F_d= Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2 traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(4) Method 6 of appendix A of this part shall be used to determine the SO_2 concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the NO_X concentration.

(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_X sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2 concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_X sample.

(iii) The NO_X emission rate shall be computed for each pair of NO_X and O_2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D2015, or D5865 (solid fuels), D240 (liquid fuels), or D1826 (gaseous fuels) (all of these methods are incorporated by reference, see §60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate (E) of PM, SO_2 and NO_X may be determined by using the Fc factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where:

E = Emission rate of pollutant, ng/J (lb/MMBtu);

C = Concentration of pollutant, ng/dscm (lb/dscf);

$\%CO_2$= CO_2concentration, percent dry basis; and

F_c= Factor as determined in appropriate sections of Method 19 of appendix A of this part.

(ii) If and only if the average Fc factor in Method 19 of appendix A of this part is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B of appendix A of this part shall be used to determine the $O_2$and CO_2concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o(average of three runs), as calculated from the equation in Method 3B of appendix A of this part, is more than ±3 percent than the average $F_o$value, as determined from the average values of $F_d$and $F_c$in Method 19 of appendix A of this part, *i.e.* , F_{oa}= 0.209 (F_{da}/F_{ca}), then the following procedure shall be followed:

(A) When $F_o$is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.* , if $F_o$is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When $F_o$is less than 0.97 $F_{oa}$and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.* , if $F_o$is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When $F_o$is greater than 1.03 $F_{oa}$and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, *e.g.* , if $F_o$is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B of appendix A–3 of this part, Method 17 of appendix A–6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A–3 of this part may be used with Method 17 of appendix A–6 of this part only if it is used after wet FGD systems. Method 17 of appendix A–6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 of appendix A of this part is used in place of the condenser (section 2.1.7) of Method 5 of appendix A of this part.

(ii) All applicable procedures in Method 8 of appendix A of this part for the determination of SO_2 (including moisture) are used:

(4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part data are specified to determine the SO_2emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2concentration (% O_2) for the emission rate correction factor.

(6) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used.

(7) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5078, Jan. 28, 2009]

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Appendix B

Arkansas Department of Environmental Quality

CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised August 2004

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS/COMS). Generally there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 CFR Part 60 or 63,
2. CEMS required by 40 CFR Part 75,
3. CEMS/COMS required by ADEQ permit for reasons other that Part 60, 63 or 75.

These CEMS/COMS conditions are not intended to supercede Part 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by ADEQ permit for reasons other than Part 60, 63, or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.

- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) - The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) - The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) - A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions - Any period in which the emissions exceed the permit limits.

Monitor Downtime - Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period - Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the RATA, RAA, or CGA which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS - The main reporting CEMS with the ability to sample, analyze, and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) - The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value – The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.

B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.

C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 CFR, Part 60, Appendix B, PS 1-9. The Department may accept alternate PST's for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the ADEQ CEM Coordinator prior to testing.

D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 CFR, Part 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval the excess zero and span drifts measured must be quantified and recorded.

E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.

F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.

G. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one hour period unless more data points are required by the permit.

H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

I. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

A. When requested to do so by an owner or operator, the ADEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.

B. Each facility which operates a CEMS/COMS shall notify the ADEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 days prior to testing. Performance test results shall be submitted to the Department within thirty days after completion of testing.

C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.

D. Except for Part 75 CEMs, each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter. Part 75 CEMs shall submit this information semi-annually and as part of Title V six (6) month reporting requirement if the facility is a Title V facility.

E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.

F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.

G. Except for Part 75 CEMs, quarterly reports shall be used by the Department to determine compliance with the permit. For Part 75 CEMs, the semi-annual report shall be used.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.

B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.

C. Facilities responsible for one, or more, CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS/COMS
   a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked and the time required to perform these checks and return to stable operation)
2. Calibration drift determination and adjustment of CEMS/COMS
   a. Out-of-control period determination
   b. Steps of corrective action
3. Preventive maintenance of CEMS/COMS
   a. CEMS/COMS information
      1) Manufacture
      2) Model number
      3) Serial number
   b. Scheduled activities (check list)
   c. Spare part inventory
4. Data recording, calculations, and reporting
5. Accuracy audit procedures including sampling and analysis methods
6. Program of corrective action for malfunctioning CEMS/COMS

D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60 Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the ADEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O_2 & CO_2)	> 1.0 % O2 or CO2
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O_2 & CO_2)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three run average or > 7.5 % of the applicable standard
Diluent (O_2 & CO_2)	> 15% of the three run average or > 7.5 % of the applicable standard

F. If either the zero or span drift results exceed two times the applicable drift specification in 40 CFR, Part 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of the successful daily zero or span drift or completion of the successful CGA, RAA or RATA.

G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

Appendix C

CSN: 04-0107
Title V Air Permit No. 276-AOP-R1

AEP - Southwestern Electric Power Company (SWEPCO)
Flint Creek Power Plant

Corrective Action Plan Based Upon Opacity Monitoring for Particulate Emissions

AEP – Southwestern Electric Power Company (SWEPCO) believes that the continuous opacity monitoring system (COMS) data is the most appropriate and readily available indicator for continuously evaluating the performance and operations of the electrostatic precipitator and thereby assessing compliance with the applicable particulate emission rate. Monitoring of other ESP operating parameters such as TR set voltage and current levels may be beneficial in evaluating ESP performance as well, however, neither are direct indicators of conditions in the stack prior to release of the flue gas. For this reason, a specific corrective action plan has been developed based upon opacity monitoring. This corrective action plan will be implemented at any time there is a significant or sudden increase in stack opacity above normal operating levels.

CSN: 04-0107
Title V Air Permit No. 276-AOP-R1

Corrective Action Procedures Summary

		Description
I.	Initiation of Corrective Action Procedures	Corrective action shall be initiated when a one-hour opacity average exceeds 20%. The plant staff that made the discovery shall immediately notify the shift supervisor or plant environmental coordinator.
II.	Time of Completion of Corrective Action Procedures	As soon as practically possible.
III.	Corrective Action Description	Corrective action will include observing the COMS data and at the same time initiate a review of other available information (such as: Transformer Rectifier status, voltage, current, operating parameters, etc.) to validate and/or identify the cause of the opacity increase, return tripped TR Sets to service (as applicable), and evaluation of the ash removal system.

Attachment A
(CAM Plan - Corrective Action Plan)

Southwestern Electric Power Company (SWEPCO)
Flint Creek Power Plant

INFORMATION TO BE COLLECTED IN CONJUNCTION WITH A SIGNIFICANT OPACITY INCREASE ABOVE NORMAL OPERATING LEVELS

A. Data to be obtained from stack continuous opacity monitoring system (COMS):

1. Time, magnitude and duration of the opacity increase?

_____

2. Was the opacity increase confirmed visually?

_____

3. Were all COMS calibration checks within specification?

_____

4. Any other indications of COMS malfunction?

_____

_____

B. Data to be obtained from unit control room(s), precipitator(s) and COMS:

Unit	#1	____	____	____	____
1. Did duct COMS show a corresponding increase?	____	____	____	____	____
2. Precipitator electrical readings normal?	____	____	____	____	____

(Attach data sheets.)

Flint Creek - INFORMATION TO BE COLLECTED IN CONJUNCTION WITH A SIGNIFICANT OPACITY INCREASE ABOVE NORMAL OPERATING LEVELS

B. (Cont'd) Unit	#1				
3. Number of TR sets O/S?					
4. Any TR sets automatically or manually tripped O/S prior to increase?					
5. Unit loads preceding and during increase?					
6. Was unit in process of startup or shutdown?					
7. Stack gas temperature during increase?					
8. Any significant operational changes which may have contributed to opacity increase?					
9. ESP rappers O/S					

C. The cause of the opacity increase has been determined to be:

_____

_____

_____

Note: "O/S" means "Out of Service".

Flint Creek Plant - INFORMATION TO BE COLLECTED IN CONJUNCTION WITH A SIGNIFICANT OPACITY INCREASE ABOVE NORMAL OPERATING LEVELS

D. Complete only if opacity increase determined to be due to equipment failure or breakdown:

1. Nature of equipment? _____

_____

_____

_____

2. Time of failure or breakdown? _____

3. Method of repair? _____

_____

_____

_____

4. Time required for repair? _____

_____

_____

Appendix D

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

FEB 28 1996

Mr. Brian Bond
Environmental Manager
Southwestern Electric Power Company
P.O. Box 21106
Shreveport, LA 71156-0001

Dear Mr. Bond:

This letter is in response to your request from Southwestern Electric Power Company (SWEPCO), dated August 22, 1995, for reconsideration of an Environmental Protection Agency (EPA) determination, dated May 16, 1995, for SWEPCO's Flint Creek Power Plant located near Gentry, Arkansas. EPA had written its determination in May of 1995 in response to a request made by the Arkansas Department of Pollution Control and Ecology (ADPC&E), dated March 23, 1995, on whether or not performance tests would be required under New Source Performance Standards (NSPS) rules when coal and fuel oil or fuel oil only are fired under certain conditions at the Flint Creek Power Plant, Unit Number 1. Your requests encompass an affected facility (Unit Number 1) that is subject to 40 CFR Part 60, Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 and Subpart A - General Provisions.

In the EPA letter, dated May 16, 1995, we told ADPC&E that NSPS performance tests would have to be conducted for all five (5) steam generating unit firing scenarios under review by the State. That EPA determination was made with the information made available at that time. That information did not contain critical items concerning frequency of firing, fuel oil percentages, plant operational characteristics, and other such information as was submitted later in August 1995. The statements made in the May 16, 1995 letter regarding the implementation of NSPS Part 60, Subparts D & A rules remain unchanged and a copy is enclosed for your review. However, additional information from SWEPCO indicated that a reevaluation would be needed.

Based on your latest submittal, dated August 22, 1995, of updated information describing the co-firing of coal and fuel and fuel oil only, we have reevaluated the need to do performance tests on Unit Number 1 for the five (5) steam generating unit firing scenarios with respect to the requirements in the NSPS rules. The new information indicates that performance tests are not needed.

A determination and its corresponding rationale for each firing scenario is provided below:

No. 1 Startup and Shutdown of Pulverizer Mills:

According to SWEPCO, as the load on the boiler is increased or decreased in the course of normal daily operation (on an on-going basis) due to startup and shutdown of pulverizer mills, co-firing of coal and fuel oil occurs. This is done to stabilize coal ignition and boiler flames. SWEPCO said that this occurs only twice a day for 15 minutes each time. At all other times, only coal is fired. SWEPCO said that the proportion of fuel oil fired represents only 0.9% of the heat input of the fuel mixture fired; 99.1% of the heat input of the mixture is coal.

Determination: A waiver from performance testing, using the provisions of Subpart A, §60.8(b)(4), is not necessary. The No.1 firing scenario is essentially the same as the coal only firing scenario, such that, SWEPCO does not need to demonstrate by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard. The firing of a fuel oil/coal mixture in which 99.1% of the heat input is obtained from coal should produce pollutant emissions not significantly different from those resulting from firing 100% coal. Performance test data has already been submitted for firing 100% coal and compliance with this firing mode has already been established. Therefore, no performance test is needed for this firing mode.

No. 2 Fuel Oil Burned to Increase Precipitator Efficiencies:

According to SWEPCO, fuel oil was burned to increase precipitator temperature and put the precipitator in a more efficient operating range. SWEPCO said that the boiler and the Electrostatic Precipitators do not need to be operated this way to consistently meet the Opacity limits. SWEPCO indicated that it does not plan to fire the unit in this mode again.

Recommendation: A waiver from performance testing is not necessary, using the provisions of Subpart A, §60.8(b)(4). If SWEPCO intends to fire in the No. 2 mode often, then a performance test may be warranted. However, SWEPCO has indicated that it does not plan to fire in this mode. Therefore, this mode does not

constitute "representative conditions" for the purpose of a performance test. A performance test will not be required, as long as this mode does not constitute "representative conditions."

No. 3 Fuel Oil Burned for Flame Stabilization when Coal is Frozen:

According to SWEPCO, Unit Number 1 is capable of supplementing frozen coal with 7.6% of the heat input of the fuel mixture from fuel oil to accommodate the ice load on the coal. However, according to SWEPCO, firing in this mode is a relatively rare event (once every 7 to 8 years).

Recommendation: A waiver from performance testing is not necessary, using the provisions of Subpart A, §60.8(b)(4). If SWEPCO has to fire in the No. 3 mode due to the frequent occurrence of frozen coal, then a performance test may be warranted. However, SWEPCO has stated that this event does not occur often. Therefore, this mode does not constitute "representative conditions" for the purpose of a performance test. A performance test is not required, as long as SWEPCO does not fire in this mode more frequently than SWEPCO stated in its letter, dated August 22, 1995.

No. 4 Fuel Oil Burned during Fuel Oil Storage Tank Inspection/Maintenance:

According to SWEPCO, in order to enable fuel oil storage tank inspections and maintenance activities, fuel oil is co-fired with coal to reduce the amount of fuel oil in the tank. SWEPCO said that this occurs only once every 15 years for only 72 hours each time. SWEPCO said that the proportion of fuel oil fired represents only 7.6% of the heat input of the fuel mixture fired; 92.4% of the heat input of the mixture is coal.

Recommendation: A waiver from performance testing is not necessary, using the provisions of Subpart A, §60.8(b)(4). If SWEPCO has to fire in the No. 4 mode due to the frequent occurrence of fuel oil tank maintenance, then a performance test may be warranted. However, SWEPCO has stated that this event does not occur often. Therefore, this mode does not constitute "representative conditions" for the purpose of a

performance test. A performance test will not be required, as long as SWEPCO does not fire in this mode more frequently than SWEPCO stated in its letter, dated August 22, 1995.

If a performance test ever becomes necessary for determination of compliance when firing in either mode No. 3 or mode No. 4, then a single performance test, conducted using the conditions of firing mode No. 3 should be sufficient to demonstrate compliance when firing in mode No. 3 and mode No. 4, since the boiler operating conditions for firing in modes No. 3 and No. 4 are very similar.

No. 5 Fuel Oil Burned during Extreme Cold Weather to Prevent Boiler Tube Failure:

According to SWEPCO, during wintertime peak electrical demand, the boiler unit is required to provide maximum load and be off line the minimum time for equipment maintenance, if necessary. During the downtime for maintenance, about 70.5 million BTU per hour of 100% fuel oil (no coal) is fired to keep the boiler warm and prevent damage due to freezing. The unit is not generating steam and is not making electricity during this event.

Recommendation: A waiver from performance testing, using the provisions of Subpart A, §60.8(b)(4), is not necessary. This mode does not constitute "representative conditions" for the purpose of a performance test. The subject boiler is in a state of "shutdown" while firing in this mode. No performance test is needed for this firing mode.

However, it should be noted that Unit Number 1 and its associated air pollution control equipment should be maintained and operated during its shutdown period in a manner consistent with good air pollution control practice for minimizing emissions (see Subpart A, §60.11(d)).

These steam generating unit performance test determinations are based primarily on EPA's evaluation of information provided on August 22, 1995. They are specific to the above referenced affected facility (Unit Number 1) located in SWEPCO's Flint Creek Power Plant. Performance test determinations for other steam generating units subject to NSPS are to be addressed on a

request-by-request basis. If any information is found that would reverse these determinations, then they could become invalid and a new evaluation would be needed.

If you have any questions concerning this determination, please contact Jon York at (214) 665-7289.

Sincerely yours,

Samuel Coleman, P.E.
Director
Compliance Assurance and
Enforcement Division (6EN)

Enclosure

cc: Glenn Proffitt
J. B. Jones
Arkansas Department of
Pollution Control and Ecology
N. N. Dharmarajan
Central and South West Services, Inc.
Chris Oh
Office of Enforcement and
Compliance Assurance
Walter Stevenson
Office of Air Quality
Performance Standards

Appendix E

Flint Creek Power Plant
Permit #: 276-AOP-R2
AFIN: 04-00107

Exhibit D

Derivation of Equations Used to Determine PM / PM_{10} Re-Testing Requirements Based on Future "New Sulfur" and "New Ash" Content of Coal Received at Flint Creek Creek Power Plant

Specific Condition #19 provides the following equations for determining subsequent PM / PM_{10} tests:

$$\left[\left((\text{New Sulfur \%} - \text{Tested Sulfur \%}) \times 822.2\right) + \left((\text{New Ash \%} - \text{Tested Ash \%}) \times 32.9\right)\right] > \left[\left(\text{Permitted PM limit, lb/hr}\right) - \left(\text{Tested PM rate, lb/hr}\right)\right]$$

or whenever:

$$\left[\left((\text{New Sulfur \%} - \text{Tested Sulfur \%}) \times 822.2\right) + \left((\text{New Ash \%} - \text{Tested Ash \%}) \times 22.2\right)\right] > \left[\left(\text{Permitted } PM_{10} \text{ limit, lb/hr}\right) - \left(\text{Tested } PM_{10} \text{ rate, lb/hr}\right)\right]$$

Derivation of factors used in the above equations is as follows:

The sulfur-related factor = 822.2

822.2 = 0.1 * 20 * 411.1

Where:

- 0.1 is from AP-42 Table 1.1-5 (condensable PM = 0.1*S - 0.03 lb/MMBtu....the 0.03 will subtract out of the equation)
- 20 MMBtu/ton is the conversion factor from lb/MMBtu to lb/ton [see footnote (e) to Table 1.1-5]
- 411.1 is the maximum hourly coal and Tire Derived Fuel (TDF) throughput

---

The ash-related factor = 32.9 (as related to the PM limit under the Title V permit)

32.9 = 0.08 * 411.1

Where:

- 0.08 is from AP-42 Table 1.1-6 (Total PM controlled with ESP)
- 411.1 is the maximum hourly coal and TDF throughput

The ash-related factor = 22.2 (as related to the PM_{10} limit under the Title V permit)

22.2 = 0.054 * 411.1

Where:

- 0.054 is from AP-42 Table 1.1-6 (PM10 controlled with ESP)
- 411.1 is the maximum hourly coal and TDF throughput

Appendix F

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Acid Rain Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31

This submission is: ☐ New ☐ Revised ☒ Renewal

STEP 1

Identify the source by plant name, State, and ORIS code.

Plant Name	State	ORIS Code
Flint Creek Power Plant	AR	6138

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a." For new units, enter the requested information in columns "c" and "d."

a	b	c	d
Unit ID#	Unit Will Hold Allowances In Accordance with 40 CFR 72.9(c)(1)	New Units Commence Operation Date	New Units Monitor Certification Deadline
1	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		

Flint Creek Power Plant
Plant Name (from Step 1)

STEP 3

Read the standard requirements

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another affected unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

STEP 3, Cont'd.

Nitrogen Oxides Requirements The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting
authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

Flint Creek Power Plant
Plant Name (from Step 1)

Step 3, Cont'd.

Liability, Cont'd.

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Certification

Read the certification statement, sign, and date

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name John M. McManus	
Signature John M McManus	Date 6/25/04

EPA

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_X Compliance Plan

Page [1] of [1]

For more information, see instructions and refer to 40 CFR 76.9

This submission is: [ ] New [X] Revised

STEP 1
Indicate plant name, State, and ORIS code from NADB, if applicable

Flint Creek	AR	6138
Plant Name	State	ORIS Code

STEP 2

Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.

	1 ID# DBW Type	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(j) NO_x Averaging Plan (include NO_x Averaging form)	[X]	[ ]	[ ]	[ ]	[ ]	[ ]
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging form)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

Flint Creek Plant Name (from Step 1)	NO$_x$ Compliance - Page 2 Page 1 of 1

STEP 2, cont'd.

	ID# 1 Type DBW	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (Include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign &

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO$_x$ as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(ii).
Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.
Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO$_x$ for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO$_x$ for Phase II units with Group 1 boilers under 40 CFR 76.7.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

John M. McManus Name	
Signature John M. McManus	December 19, 2006 Date

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_x Averaging Plan

For more information, see instructions and refer to 40 CFR 76.11

This submission is: [ ] New [X] Revised

STEP 1

Identify the units participating in this averaging plan by plant name, State, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation (ACEL) in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) ACEL	(c) Annual Heat Input Limit
Rockport	IN	MB1	0.46	0.46	88,636,400
Rockport	IN	MB2	0.46	0.46	93,566,400
Tanners Creek	IN	U1	0.80	0.80	8,960,400
Tanners Creek	IN	U2	0.80	0.80	9,839,600
Tanners Creek	IN	U3	0.80	0.80	10,605,200
Tanners Creek	IN	U4	0.86	0.86	28,043,800
Big Sandy	KY	BSU1	0.46	0.46	16,002,200
Big Sandy	KY	BSU2	0.46	0.46	51,126,800
Conesville	OH	3	0.50	0.50	3,518,200

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
.56	≤	.56

$$\frac{\sum_{i=1}^{n} (R_{Li} \times HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} [R_{1i} \times HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emission limitation for unit i, in lb/mmBtu, as specified in column (b) of Step 1;

R_{1i} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

Flint Creek Plant Name (from Step 1)

STEP 3

Mark one of the two options and enter dates.

[X] This plan is effective for calendar year 2007 through calendar year 2011 unless notification to terminate the plan is given.

[ ] Treat this plan as [ ] identical plans, each effective for one calendar year for the following calendar years: _____, _____, _____, _____ and _____ unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,
(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name: John M. McManus	
Signature: John M. McManus	Date: December 19, 2006

Flint Creek
Plant Name (from Step 1)

STEP 1

Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Conesville	OH	4	0.45	0.45	44,976,190
Conesville	OH	5	0.40	0.40	25,434,200
Conesville	OH	6	0.40	0.40	24,905,400
Muskingum	OH	1	0.84	0.84	8,796,800
Muskingum	OH	2	0.84	0.84	8,181,600
Muskingum	OH	3	0.86	0.86	8,251,800
Muskingum	OH	4	0.86	0.86	8,143,200
Muskingum	OH	5	0.68	0.68	35,606,400
Picway	OH	9	0.50	0.50	3,432,400
Clinch River	VA	1	0.80	0.80	11,366,000
Clinch River	VA	2	0.80	0.80	14,350,000
Clinch River	VA	3	0.80	0.80	14,544,000
Glen Lyn	VA	51	0.40	0.40	1,581,500
Glen Lyn	VA	52	0.40	0.40	1,581,500
Glen Lyn	VA	6	0.46	0.46	5,930,000
John E Amos	WV	1	0.46	0.46	52,512,000
John E Amos	WV	2	0.46	0.46	52,031,200
John E Amos	WV	3	0.68	0.68	88,228,800
Kammer	WV	1	0.86	0.86	11,214,400
Kammer	WV	2	0.86	0.86	11,570,600
Kammer	WV	3	0.86	0.86	11,498,000
Kanawha	WV	1	0.80	0.80	10,392,600
Kanawha	WV	2	0.80	0.80	9,018,200
Mitchell	WV	1	0.50	0.50	50,415,600
Mitchell	WV	2	0.50	0.50	53,611,600
Mountaineer	WV	1	0.46	0.46	97,048,400
Sporn	WV	11	0.80	0.80	7,467,000

Flint Creek

Plant Name (from Step 1)

STEP 1

Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Sporn	WV	21	0.80	0.80	7,203,600
Sporn	WV	31	0.80	0.80	7,733,800
Sporn	WV	41	0.80	0.80	8,083,200
Sporn	WV	51	0.46	0.46	13,054,800
Cardinal	OH	1	0.68	0.68	37,568,400
Cardinal	OH	2	0.68	0.68	39,809,200
Cardinal	OH	3	0.46	0.46	39,209,000
Gavin	OH	1	0.68	0.68	86,301,600
Gavin	OH	2	0.68	0.68	93,845,000
Flint Creek	AR	1	0.46	0.46	37,879,000
Northeastern	OK	3313	0.40	0.40	33,560,000
Northeastern	OK	3314	0.40	0.40	35,524,000
Oklaunion	TX	1	0.46	0.46	44,826,000
Pirkey	TX	1	0.46	0.46	51,699,000
Welsh	TX	1	0.46	0.46	37,588,000
Welsh	TX	2	0.46	0.46	37,923,000
Welsh	TX	3	0.46	0.46	39,080,000

Appendix G

TITLE V PERMIT
SUPPLEMENTAL PACKAGE
CLEAN AIR INTERSTATE RULE PERMIT APPLICATION

AFIN:	04-00107	Date:	June 16, 2008

1. UNIT INFORMATION

Enter the Source ID and Description (as identified in your Arkansas Title V Permit).

Source Number	Description
SN-01	Main Boiler

2. STANDARD REQUIREMENTS

Read the standard requirements and the certification. Enter the name of the CAIR designated representative, and sign and date. Include the supplemental application along with a completed Arkansas Operating Permit (Major Source) General Information Forms (pages 1-6). The Department will process a modification to the facility's Title V permit to incorporate these CAIR requirements.

NO_x Ozone Season Emission Requirements

§ 96.306 Standard requirements

(a) *Permit requirements.*

(1) The CAIR designated representative of each CAIR NO_X Ozone Season source required to have a title V operating permit and each CAIR NO_X Ozone Season unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.322 in accordance with the deadlines specified in §96.321(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO_X Ozone Season source required to have a title V operating permit and each CAIR NO_X Ozone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of 40 CFR part 96 for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart IIII of 40 CFR part 96, the owners and operators of a CAIR NO_X Ozone Season source that is not otherwise required to have a title V operating permit and

each CAIR NO_X Ozone Season unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCCC of 40 CFR part 96 for such CAIR NO_X Ozone Season source and such CAIR NO_X Ozone Season unit.

(b) *Monitoring, reporting, and recordkeeping requirements.*
(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of 40 CFR part 96.
(2) The emissions measurements recorded and reported in accordance with subpart HHHH of 40 CFR part 96 shall be used to determine compliance by each CAIR NO_X Ozone Season source with the CAIR NO_X Ozone Season emissions limitation under paragraph (c) of this §96.306.

(c) *Nitrogen oxides ozone season emission requirements.*
(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under §96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with subpart HHHH of this part.
(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of this §96.306 starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.370(b)(1), (2), (3), or (7) and for each control period thereafter.
(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.306, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.
(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with subparts, FFFF, GGGG of 40 CFR part 96 and Chapter 14 of the Arkansas Pollution Control and Ecology Commission Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control.
(5) A CAIR NO_X Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.
(6) A CAIR NO_X Ozone Season allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart FFFF, GGGG of this part or Chapter 14 of the Arkansas Pollution Control and Ecology Commission Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

(d) *Excess emissions requirements.*
(1) If a CAIR NO_X Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO_X Ozone Season emissions limitation, then:
(i) The owners and operators of the source and each CAIR NO_X Ozone Season unit at the source shall surrender the CAIR NO_X Ozone Season allowances required for deduction under §96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) *Recordkeeping and reporting requirements.*
(1) Unless otherwise provided, the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §96.313 for the CAIR designated representative for the source and each CAIR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.313 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHHH of 40 CFR part 96, provided that to the extent that subpart HHHH of 40 CFR part 96 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Ozone Season Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Ozone Season Trading Program.
(2) The CAIR designated representative of a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall submit the reports required under the CAIR NO_X Ozone Season Trading Program, including those under subpart HHHH of 40 CFR part 96.

(f) *Liability.*
(1) Each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit shall meet the requirements of the CAIR NO_X Ozone Season Trading Program.
(2) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season source or the CAIR designated representative of a CAIR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the CAIR NO_X Ozone Season units at the source.
(3) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season unit or the CAIR designated representative of a CAIR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.*
No provision of the CAIR NO_X Ozone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X Ozone Season source or CAIR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

3. CERTIFICATION

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

CAIR Designated Representative

Name (Print) John McManus	
Signature John McManus	**Date** 6/30/08

CERTIFICATE OF SERVICE

I, Cynthia Hook, hereby certify that a copy of this permit has been mailed by first class mail to American Electric Power - Flint Creek Power Plant, P.O. Box 660164, Dallas, TX, 75266, on this 30th day of December, 2009.

Pam Owen

for Cynthia Hook, AAII, Air Division