ADEQ

ARKANSAS
Department of Environmental Quality

January 22, 2010

Dale King, Environmental Manager
Bekaert Corporation
1881 Bekaert Drive
Van Buren, AR 72958

Dear Mr. King:

The enclosed Permit No. 0299-AR-15 is your authority to construct, operate, and maintain the equipment and/or control apparatus as set forth in your application initially received on 8/13/2009.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. 0299-AR-15 for the construction, operation and maintenance of an air pollution control system for Bekaert Corporation 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

Mike Bates
Chief, Air Division

Enclosure

ADEQ
MINOR SOURCE
AIR PERMIT

Permit No. : 0299-AR-15

IS ISSUED TO:

Bekaert Corporation
1881 Bekaert Drive
Van Buren, AR 72958
Crawford County
AFIN: 17-00043

THIS PERMIT IS THE ABOVE REFERENCED PERMITTEE'S AUTHORITY TO CONSTRUCT, MODIFY, OPERATE, AND/OR MAINTAIN THE EQUIPMENT AND/OR FACILITY IN THE MANNER AS SET FORTH IN THE DEPARTMENT'S MINOR SOURCE AIR PERMIT AND THE APPLICATION. THIS PERMIT IS ISSUED PURSUANT TO THE PROVISIONS OF THE ARKANSAS WATER AND AIR POLLUTION CONTROL ACT (ARK. CODE ANN. SEC. 8-4-101 *ET SEQ.*) AND THE REGULATIONS PROMULGATED THEREUNDER, AND IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates

Mike Bates
Chief, Air Division

January 22, 2010
Date

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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
No.	Number
NO_x	Nitrogen Oxide
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than Ten Microns
SO_2	Sulfur Dioxide
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

Section I: FACILITY INFORMATION

PERMITTEE:	Bekaert Corporation
AFIN:	17-00043
PERMIT NUMBER:	0299-AR-15
FACILITY ADDRESS:	1881 Bekaert Drive Van Buren, AR 72958
MAILING ADDRESS:	1881 Bekaert Drive Van Buren, AR 72958
COUNTY:	Crawford County
CONTACT NAME:	Dale King
CONTACT POSITION:	Environmental Manager
TELEPHONE NUMBER:	479-474-5211
REVIEWING ENGINEER:	Travis Porter
UTM North South (Y):	Zone 15: 3924548.04 m
UTM East West (X):	Zone 15: 373572.53 m

Section II: INTRODUCTION

Summary of Permit Activity

In the previous permit, Bekaert requested to add a third dust collector, SN-80, to two other existing collectors removing particulates from a group of wire drawing machines. The dust collector was not installed, and the Company requests that the source, SN-80, be removed from the permit. The particulates from this group of wire drawing machines will be collected by two dust collectors instead of three, as is in the active permit. In addition, Bekaert requests authority to replace two existing 28 MMBtu/hr boilers, SN-42 and SN-43, (vintage circa 1972) with two new, more efficient, 14.7 MMBtu/hr boilers, which will result in reduced emissions. They will use existing stacks, and the source numbers will remain the same. The Company also requests to bubble emissions for SN-42 and SN-43. Permitted PM and PM_{10} emissions will decrease by 0.4 tpy each, due to rounding.

Process Description

Steel wire rod is prepared for wire drawing by chemical pickling in an HCl acid solution (SN-01), water rinsed (SN-02), coated with one of two wire protectorants (SN-03), and dried (SN-04 and SN-05). The rod can now be dipped in the zinc phosphate, rinsed, coated, and then dried as an additional step. The wire rod is then drawn on one of several wire drawing machines (dust emissions collected by SN-06, SN-53, SN-62 and SN-80) to become "bright" wire. Dryer emissions from the new zinc phosphate line dryer (SN-79) will vent through windows, doors, etc. Some wire also is further processed through redraw where the bright wire is put through the drawing process a second time in order to further reduce the diameter of the wire (SN-64, SN-66, and SN-78). The Re-Draw Department also has two roof ventilation fans (SN-76 and SN-77). The bright wire is processed further on one of three (3) lines utilizing two (2) types of hot dip galvanizing processes. The lines differ mainly in the heat treating and galvanizing process. The first type of hot dip galvanizing line is identified as the IPV 40 line. Bright wire is heat treated in a patenting furnace, quenched in molten lead baths, and cooled in a water bath (SN-25, SN-26, SN-27, SN-28, and SN-29). The wire receives further cleaning in an HCl pickling bath (SN-30 and SN-31). A flux coating is then applied (SN-32) and dried (SN-33 and SN-34). A zinc coating is then applied to the wire via dipping in a bath of molten zinc and/or a bath containing a mixture of molten zinc and aluminum (SN-35, SN-36). Final steps involve cooling and application of surface protectorants (SN-37, SN-39, SN-56, SN-57 and SN-58).

The second type of galvanizing process is used on the IVD 40 and IVD 60 lines. Bright wire is heat treated in molten lead baths and water quenched (SN-08, SN-09, SN-17 and SN-18). The wire receives further cleaning in an HCl pickling bath (SN-10 and 19) and water rinse bath (SN-45 and SN-48). A flux coating is then applied (SN-11 and SN-20) and dried (SN-12 and SN-21). A zinc coating is then applied to the wire via dipping in a bath of molten zinc or a bath containing a mixture of molten zinc and aluminum (IVD 40) (SN-13, SN-14, SN-22, SN-23 and SN-44). Final steps involve cooling and application of surface protectorants (SN-15, SN-24, and SN-50).

Several mechanical finishing operations are performed on a portion of the galvanized and/or bright wire delivered from the lines described above. Of these operations, only the Welded Wire Field Fence spot welding machine (SN-40), the Wire Concrete Additive drying oven (SN-41), the Galvanized Redrawing dust collectors (SN-64, SN-66 and SN-78), the Strand Coating Applicator (SN-57), and six (SN-59, SN-70 through SN-74) welded wire machines have air emission sources.

Two 28 MMBtu/hr water tube boilers are located within the plant and are used to provide process steam, steam heat, and hot water. These natural gas fired boilers are designated "service" and "standby." Only one system is required to be fired for plant steam demand; the other is in a cold standby state. Products of natural gas combustion are exhausted through two stacks (SN-42 and SN-43), which serve each boiler, respectively. With the exception of startup/shutdown, they do not operate simultaneously. Two times/year, under Normal operating conditions, the operating boiler will continue to operate up to 8 hours while the standby boiler is brought on line and reaches operating temperature. At that time, the first boiler is shut down. The base case is the existing situation, with two 28 MMBtu/hr boilers.

Bekaert plans to replace these aging boilers. The plan is to replace one late in 2009 and the second one in 2010. The new boilers will be 14.7 MMBtu/hr natural-gas fired boilers. They will use the same stacks as the existing boilers. The existing situation, or base case, represents operating the two existing boilers. Two alternative scenarios are approved in this permit.

> Alternative Scenario #1. One of the existing 28MM Btu/hr boilers is replaced with a new 14.7 MMBtu/hr boiler. The second 28MM Btu/hr boiler remains.
>
> Alternative Scenario #2. The second 28MM Btu/hr boiler is replaced with a new 14.7 MM Btu/hr boiler. At this point, both old boilers have been replaced.

The emission of hydrochloric acid originates from the pickling and electro-chemical baths. These emissions are controlled by either packed column or sieve tray scrubbers (SN-01, SN-10, SN-19, and SN-30) (98% efficiency).

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
40 CFR Part 60, Subpart Dc – *Standards of Performance for Small Industrial – Commercial – Institutional Steam Generating Units*

Total Allowable Emissions

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

TOTAL ALLOWABLE EMISSIONS		
Pollutant	Emission Rates	
	lb/hr	tpy
PM	10.3	29.1
PM_{10}	10.3	29.1
SO_2	4.5	11.9
VOC	2.5	4.7
CO	5.3	12.5
NO_X	15.1	45.1
Lead (Pb)	0.3	0.3
Chlorine (Cl_2)	0.9	2.20
Hydrogen Chloride (HCl)	2.23	8.74
Ammonia (NH_3/NH_4)	2.70	11.00

Section III: PERMIT HISTORY

299-A	Initial air permit for Bekaert Corporation. It established process and emission limits for the facility.
299-AR-1	Issued 11/28/89 and addressed emission changes within the facility.
299-AR-2 299-AR-3	Issued 1/20/93 and 3/17/94 which established emission limits following process changes at the facility.
299-AR-4	Issued 7/25/95 and updated all sources into one application due to past permit modifications and future production increases. Emissions data for the facility were modified slightly due to emission test results. Two additional sources were added which included a wire drawing department exhaust (SN-53) and a wax bath vacuum wipe (SN-54).
299-AR-5	Issued 1/29/96 and included the addition of a new pickling inhibitor chemical in the rod pickling HCl tanks and required the facility to measure the pressure drop across the sieve trays on SN-10 and SN-19 instead of measuring across the scrubbers.
299-AR-6	Issued 8/13/96 as a minor modification which involved the replacement of the EG 32 (electro-galvanizing) line with another Hot Dip line similar to the previously permitted IVD 40 and 60 lines. The IPV 40 sources, from the heat treating steps through the pickling steps, are the same type as the currently permitted EG 32 line. This replacement eliminated sulfuric acid from Bekaert's galvanizing process lines. The IPV 40 and the IVD 40 lines also have an additional hot dip step involving a mixture of zinc and aluminum. The operation of the IPV 40 line resulted in a total plant operational capacity increase of approximately 16%. From this modification, emissions of zinc sulfate, sulfuric acid, and sulfate were eliminated. The most significant increases in emissions were due mainly to more natural gas combustion and a larger pickling bath.
299-AR-7	Issued 4/25/97 and with the following modifications: modified SN-29 to include fugitive and the vacuum wipe emissions on the East side of the IPV 40 line; deleted SN-31 and ducted to SN-30 inlet; added a point source to include fugitive and the vacuum wipe emissions on the West side of the IPV 40 line as SN-31; combined sources 38, 39, and 57 into one source renumbered as SN-38; combined sources 55, 59, and 61 into one source renumbered as SN-39; added source emissions for IPV 40 air knife exhaust as SN-55; added a source number for the Wire drawing Dept. Hand vacuum system (SN-62); added the redraw dept. Dust Collector and Hand vacuum system (SN-63 and 64); added source emissions for the strand coating applicator as SN-57.
299-AR-8	Issued 10/27/97 and involved adding Dust Collector No. 2 (SN-61) to the Redraw Dept.

229-AR-9	Issued 6/30/99 and authorized the removal of collectors on the lead annealing process (SN-7 and SN-16) and added SN-65 and SN-66 (dust collectors). This permit also authorized the installation of the welded wire machines (SN-59).
299-AR-10	Issued 3/8/01 and covered the addition of three new ventilation fan stacks (SN-67, SN-68, and SN-69) for the wire drawing building. In addition, emissions for several permitted sources (06, 28, 40, 50, 51, 53, 55, 59, 61-66) were changed due to updated calculation methodologies.
299-AR-11	Issued 7/14/03 and included the addition of SN-70 through SN-74 to quantify emissions from each separate wire welding machine stack; installation of a new air knife system (SN-75), similar to currently permitted SN-55; installation of new vacuum wipe systems on the galvanizing line HCl baths which will discharge into the current scrubber system, causing a slight increase in HCl emissions for SN-01, SN-10, SN-19, and SN-30; and increase inhibitor usage (SN-01) to 1650 gallons per year. Emission increases were 1.1 ton/yr VOC, 0.5 ton/yr zinc oxide, and 0.24 ton/yr HCl.
0299-AR-12	Issued 8/10/06 and authorized the following modifications: removal of the dust collector for SN-40; removal of dust collectors SN-61, SN-63, and SN-65 and route these emissions to SN-66 and the dust collector from SN-40 (new SN-78); add two roof ventilation fans (SN-76 and SN-77); and re-designate aluminum, zinc, and zinc oxide as PM/PM_{10} instead of HAPs. Total facility emissions were permitted at: 31.5 tpy PM/PM_{10}, 11.8 tpy SO_2, 4.6 tpy VOC, 11.9 tpy CO, 44.4 tpy NO_X, 0.3 tpy Pb, 2.2 tpy Cl_2, 8.74 tpy HCl, 11.0 tpy NH_3/NH_4.
0299-AR-13	Issued 3/7/07 and authorized the following modification: add a stand alone zinc phosphate coating process. This process included three liquid baths (zinc phosphate, rinse, and borax coating) and a 1.5 MMBtu/hr drying furnace (SN-79). Permitted annual emission increases associated with this change are: 0.1 tpy PM, 0.1 tpy PM_{10}, 0.1 tpy SO_2, 0.1 tpy VOC, 0.6 tpy CO, and 0.7 tpy NO_X. It was amended on 11/12/08 to authorize removal of three Vacuum Bath Wipe Systems (SN-38, 46, and 47) and designated one new and three existing Quench Air Knives (formerly SN-55 and SN-75) to the Insignificant Activities (A-13) list. The permit template was also updated.
0299-AR-14	Issued on 5/5/2009 and authorized the following modification: installed four new dry drawing machines with a new dust collector (SN-80). Emissions from the Wire Drawing Department were formerly split equally between two exhaust systems (SN-06 and SN-53). The emissions from the Wire Drawing Department are now split equally among three exhaust systems (SN-06, 53 and 80). Changes in total permitted emissions were: 0.6 tpy PM/PM10.

Section IV: EMISSION UNIT INFORMATION

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by operating at or less than maximum capacity and by complying with Specific Conditions #6, #9 and #11. The limits specified for sources SN-42 & SN-43 apply until either Alternative Scenario # 1 or Alternative Scenario #2 are implemented. [Regulation 19, §19.501 et seq., and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
01	HCl Pickling Baths/Rod Pickling w/Scrubber	VOC	0.5	1.9
02	Borax Coating Bath/Pickling	PM_{10}	0.1	0.1
03	Lime Coating Bath/Pickling	PM_{10}	0.1	0.1
04	Drying Furnace #1/Pickling (natural gas, 2.5 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.1 0.3	0.1 0.1 0.1 0.3 1.1
05	Drying Furnace #2/Pickling (natural gas, 2.5 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.1 0.3	0.1 0.1 0.1 0.3 1.1
06	Wire Drawing Dept. Exhaust System #1	PM_{10}	1.1	4.6
07	Heat Treatment Lead Bath	PM_{10} SO_2 CO NO_X Pb	0.1 0.3 0.1 0.2 0.1	0.1 1.4 0.2 1.0 0.1
08	Heat Treatment Lead Bath Furnace (natural gas, 7.6 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.2 0.8	0.4 0.1 0.2 0.7 3.4
09	Quench Bath	PM_{10}	0.1	0.1
11	Fluxing Bath	PM_{10}	0.1	0.1

SN	Description	Pollutant	lb/hr	tpy
12	Drying Furnace (natural gas)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.1 0.1	0.1 0.1 0.1 0.1 0.4
13	Hot Dip Galvanizing Kettle	PM_{10} SO_2 CO NO_X	0.1 0.5 0.1 0.1	0.5 2.2 0.1 0.2
14	Hot Dip Galvanizing Bath (natural gas, 3.7 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.1 0.4	0.2 0.1 0.2 0.4 1.7
15	Wax Bath	SO_2 CO	0.1 0.1	0.1 0.1
16	Heat Treatment Lead Bath	PM_{10} SO_2 CO NO_X Pb	0.1 0.2 0.1 0.2 0.1	0.1 0.6 0.2 0.6 0.1
17	Heat Treatment Lead Bath (natural gas, 8.6 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.2 0.9	0.5 0.1 0.2 0.8 3.8
18	Quench Bath	PM_{10}	0.1	0.1
20	Fluxing Bath	PM_{10}	0.1	0.1
21	Drying Furnace (natural gas, 0.56 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.1 0.1	0.1 0.1 0.1 0.1 0.3
22	Hot Dip Galvanizing Kettle	PM_{10} SO_2 CO NO_X	0.1 0.5 0.1 0.1	0.5 2.2 0.1 0.2
23	Hot Dip Galvanizing Bath Furnace (natural gas, 3.4 MMBtu/hr)	PM_{10} SO_2 VOC CO	0.1 0.1 0.1 0.1	0.2 0.1 0.1 0.4

SN	Description	Pollutant	lb/hr	tpy
		NO_X	0.4	1.5
24	Wax Bath	SO_2 CO	0.1 0.1	0.1 0.1
25	Patenting Furnace (natural gas, 11 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.2 0.1 0.1 0.4 1.6	0.7 0.1 0.2 1.7 6.8
26	Heat Treatment Lead Bath	PM_{10} SO_2 CO NO_X Pb	0.1 0.2 0.1 0.2 0.1	0.1 1.0 0.2 0.7 0.1
27	Heat Treatment Lead Bath Furnace (natural gas, 1.5 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.1 0.2	0.1 0.1 0.1 0.2 0.7
28	Heat Treatment Lead Bath	PM_{10}	0.1	0.1
29	Quench Bath and Vacuum Wipe East	PM_{10}	0.1	0.1
31	Quench Bath and Vacuum Wipe West	PM_{10}	0.1	0.1
32	Fluxing Bath	PM_{10}	0.1	0.2
33	West Drying Oven (natural gas)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.1 0.3	0.2 0.1 0.1 0.3 1.0
34	East Drying Oven (natural gas)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.1 0.3	0.2 0.1 0.1 0.3 1.0
35	Hot Dip Galvanizing Kettles	PM_{10} SO_2 CO NO_X	0.4 0.5 0.1 0.1	1.7 2.2 0.1 0.2
36	BEZINAL Bath Furnace (natural gas)	PM_{10} SO_2 VOC CO	0.1 0.1 0.1 0.1	0.1 0.1 0.1 0.2

SN	Description	Pollutant	lb/hr	tpy
		NO_X	0.2	0.5
37	West Light Wax Bath	SO_2 CO	0.1 0.1	0.1 0.1
39	East Cooling & Wax Baths Vacuum Wipe Systems	PM_{10}	0.3	1.0
40	Welded Field Fence/Finished Products	PM_{10}	0.1	0.1
41	Dramix Electric Drying Oven Finished Products	PM_{10} VOC	0.1 0.1	0.1 0.1
42	Service Boiler #1 (natural gas, 28 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.4 0.1 0.2 1.0 4.0	1.8 0.2 0.8 4.4 17.8
43	Service Boiler #2 (natural gas, 28 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.4 0.1 0.2 1.0 4.0	
44	BEZINAL Bath Furnace (natural gas)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.1 0.1	0.1 0.1 0.1 0.2 0.4
50	Zinc Quench Bath Area Ventilation	PM_{10}	0.1	0.1
51	Zinc Quench Bath Area Ventilation	PM_{10}	0.1	0.1
53	Wire Drawing Dept Exhaust System #2	PM_{10}	1.1	4.6
54	Wax Bath Vacuum Wipe	PM_{10}	0.3	1.3
56	West Standard Wax Bath	SO_2 CO	0.1 0.1	0.1 0.1
57	Strand Coating Applicator	PM_{10}	0.1	0.4
58	East Standard Wax Bath	SO_2 CO	0.1 0.1	0.1 0.1
59	Welded Wire Machine #1 Stack	PM_{10}	0.1	0.1
60	East Light Wax Bath	SO_2 CO	0.1 0.1	0.1 0.1
62	Wire Drawing Dept. Hand Vacuum System	PM_{10}	0.3	1.3

SN	Description	Pollutant	lb/hr	tpy
64	Redraw Dept. Hand Vacuum System	PM_{10}	0.2	0.4
66	Redraw Dept Dust Collector System #4	PM_{10}	0.4	1.4
67	Wire Drawing Department VF#1	PM_{10}	0.2	0.6
68	Wire Drawing Department VF#2	PM_{10}	0.2	0.6
69	Wire Drawing Department VF#3	PM_{10}	0.2	0.6
70	Welded Wire Machine #2 Stack	PM_{10}	0.1	0.1
71	Welded Wire Machine #3 Stack	PM_{10}	0.1	0.1
72	Welded Wire Machine #4 Stack	PM_{10}	0.1	0.1
73	Welded Wire Machine #5 Stack	PM_{10}	0.1	0.1
74	Welded Wire Machine #6 Stack	PM_{10}	0.1	0.1
76	Vent Fan #1 Redraw Dept. Roof	PM_{10}	0.1	0.4
77	Vent Fan #2 Redraw Dept. Roof	PM_{10}	0.1	0.4
78	Redraw Dept. Soap Dust Collector #5	PM_{10}	0.4	1.4
79	Drying Furnace/Zinc Phosphate Line (natural gas, 1.5 MM Btu/hr)	PM_{10} SO_2 VOC CO NO_X	0.1 0.1 0.1 0.2 0.2	0.1 0.1 0.1 0.6 0.7
49, 55, 75	Insignificant Activities			
38, 46, 47, 61, 63, 65	Removed from Service			
80	Collector Never Installed			

2. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by operating at or less than maximum capacity and by complying with Specific Conditions #6, #9 and #11. The limits specified for sources SN-42 & SN-43 apply until either Alternative Scenario # 1 or Alternative Scenario #2 are implemented. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
01	HCl Pickling Baths/Rod Pickling w/Scrubber	HCl	0.45	1.90
02	Borax Coating Bath/Pickling	PM	0.1	0.1
03	Lime Coating Bath/Pickling	PM	0.1	0.1
04	Drying Furnace #1/Pickling (natural gas, 2.5 MMBtu/hr)	PM	0.1	0.1
05	Drying Furnace #2/Pickling (natural gas, 2.5 MMBtu/hr)	PM	0.1	0.1
06	Wire Drawing Dept. Exhaust System #1	PM	1.1	4.6
07	Heat Treatment Lead Bath	PM	0.1	0.1
08	Heat Treatment Lead Bath Furnace (natural gas, 7.6 MMBtu/hr)	PM	0.1	0.4
09	Quench Bath	PM	0.1	0.1
10	Chemical/Electro-Chemical Pickling w/Scrubber	HCl	0.52	2.18
11	Fluxing Bath	PM Chlorine Ammonia	0.1 0.10 0.1	0.1 0.10 0.2
12	Drying Furnace	PM	0.1	0.1
13	Hot Dip Galvanizing Kettle	PM Chlorine Ammonia	0.1 0.20 0.8	0.5 0.60 3.4
14	Hot Dip Galvanizing Bath (natural gas, 3.7 MMBtu/hr)	PM	0.1	0.2
16	Heat Treatment Lead Bath	PM	0.1	0.1
17	Heat Treatment Lead Bath (natural gas, 8.6 MMBtu/hr)	PM	0.1	0.5
18	Quench Bath	PM	0.1	0.1
19	Chemical/Electro-Chemical Pickling w/Scrubber	HCl	0.43	1.81
20	Fluxing Bath	PM Chlorine Ammonia	0.1 0.10 0.1	0.1 0.10 0.2
21	Drying Furnace (natural gas, 0.56 MMBtu/hr)	PM	0.1	0.1
22	Hot Dip Galvanizing Kettle	PM Chlorine Ammonia	0.1 0.20 0.8	0.5 0.60 3.4

SN	Description	Pollutant	lb/hr	tpy
23	Hot Dip Galvanizing Bath Furnace (natural gas, 3.4 MMBtu/hr)	PM	0.1	0.2
25	Patenting Furnace (natural gas, 11 MMBtu/hr)	PM	0.2	0.7
26	Heat Treatment Lead Bath	PM	0.1	0.1
27	Heat Treatment Lead Bath Furnace (natural gas, 1.5 MMBtu/hr)	PM	0.1	0.1
28	Heat Treatment Lead Bath (Vent Stack)	PM	0.1	0.1
29	Quench Bath and Vacuum Wipe East	PM	0.1	0.1
30	Chemical/Electro-Chemical Pickling w/Scrubber	HCl	0.63	2.65
31	Quench Bath and Vacuum Wipe West	PM	0.1	0.1
32	Fluxing Bath	PM Chlorine Ammonia	0.1 0.10 0.1	0.2 0.20 0.4
33	West Drying Oven (natural gas)	PM	0.1	0.2
34	East Drying Oven (natural gas)	PM	0.1	0.2
35	Hot Dip Galvanizing Kettles	PM Chlorine Ammonia	0.4 0.20 0.8	1.7 0.60 3.4
36	BEZINAL Bath Furnace (natural gas)	PM	0.1	0.1
39	East Cooling & Wax Baths Vacuum Wipe Systems	PM	0.3	1.0
40	Welded Field Fence/Finished Products	PM	0.1	0.1
41	Dramix Electric Drying Oven Finished Products	PM	0.1	0.1
42	Service Boiler #1 (natural gas, 28 MMBtu/hr)	PM	0.4	1.8
43	Service Boiler #2 (natural gas, 28 MMBtu/hr)	PM	0.4	
44	BEZINAL Bath Furnace	PM	0.1	0.1
45	Pickling Final Rinse Vacuum Wipe	HCl	0.10	0.10
48	Pickling Final Rinse Vacuum Wipe	HCl	0.10	0.10

SN	Description	Pollutant	lb/hr	tpy
50	Zinc Quench Bath Area Ventilation	PM	0.1	0.1
51	Zinc Quench Bath Area Ventilation	PM	0.1	0.1
53	Wire Drawing Dept Exhaust System #2	PM	1.1	4.6
54	Wax Bath Vacuum Wipe	PM	0.3	1.3
57	Strand Coating Applicator	PM	0.1	0.4
59	Welded Wire Machine #1 Stack	PM	0.1	0.1
62	Wire Drawing Dept. Hand Vacuum System	PM	0.3	1.3
64	Redraw Dept. Hand Vacuum System	PM	0.2	0.4
66	Redraw Department Dust Collector System #4	PM	0.4	1.4
67	Wire Drawing Department VF #1	PM	0.2	0.6
68	Wire Drawing Department VF #2	PM	0.2	0.6
69	Wire Drawing Department VF #3	PM	0.2	0.6
70	Welded Wire Machine #2 Stack	PM	0.1	0.1
71	Welded Wire Machine #3 Stack	PM	0.1	0.1
72	Welded Wire Machine #4 Stack	PM	0.1	0.1
73	Welded Wire Machine #5 Stack	PM	0.1	0.1
74	Welded Wire Machine #6 Stack	PM	0.1	0.1
76	Vent Fan #1 Redraw Dept. Roof	PM	0.1	0.4
77	Vent Fan #2 Redraw Dept. Roof	PM	0.1	0.4
78	Redraw Dept. Soap Dust Collector #5	PM	0.4	1.4
79	Drying Furnace/Zinc Phosphate Line (natural gas, 1.5 MM Btu/hr)	PM	0.1	0.1
49, 55, 75	Insignificant Activities			
38, 46, 47, 61, 63, 65	Removed from Service			
80	Collector Never Installed			

Scrubber Designation	Acceptable Pressure Drop (Inches of Water)
Pickling / IPV 40 (SN-30)	5 to 8

If the pressure drop falls out of the acceptable range then this shall be noted on the daily record keeping and the corrective action shall also be noted. Corrective action for the problem shall be taken within 24 hours. If the pressure drop cannot be corrected to an acceptable level within 24 hours, then this process shall be shut down until the problem is resolved. These records shall be kept on-site and shall be made available to Department personnel upon request.

Alternative Scenario #1 Conditions for SN-42 & SN-43

14. At the point Alternative Scenario #1 is implemented, the permittee shall not exceed the emission rates set forth in the following table for sources SN-42 & SN-43. This replaces the emission limits specified for SN-42 & SN-43 in SC #1. [Regulation 19, §19.501 et seq., and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
42 or 43	Service Boiler #1 (natural gas, 28 MMBtu/hr)	PM_{10} SO_2 VOC CO NO_X	0.4 0.1 0.2 1.0 4.0	1.8 0.2 0.8 17.8
42 (New) or 43 (New)	Service Boiler #2 (natural gas, 14.7 MMBtu/hr) Replaces 28 MMBtu/hr boiler	PM_{10} SO_2 VOC CO NO_X	0.2 0.1 0.1 1.3 1.6	

15. At the point Alternative Scenario #1 is implemented, the permittee shall not exceed the emission rates set forth in the following table for sources SN-42 and SN-43. This replaces the emission limits specified for SN-42 & SN-43 in SC #2. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
42 or 43	Service Boiler #1 (natural gas, 28 MMBtu/hr)	PM	0.4	1.8

SN	Description	Pollutant	lb/hr	tpy
42 (New) or 43 (New)	Service Boiler #2 (natural gas, 14.7 MMBtu/hr)	PM	0.2	

16. Natural gas consumption for the boilers, SN-42 and SN-43, combined, shall not exceed 24.41 MM CF/month. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

17. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #16. The permittee shall update the records by the fifteenth day of the month following the month to which the records pertain. The permittee will keep the records onsite, and make the records available to Department personnel upon request. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Alternative Scenario #2 Conditions for SN-42 & SN-43

18. At the point Alternative Scenario #2 is implemented, the permittee shall not exceed the emission rates set forth in the following table for sources SN-42 & SN-43. This replaces the emission limits specified for SN-42 & SN-43 in SC #1. [Regulation 19, §19.501 et seq., and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
42 (New)	Service Boiler #1 (natural gas, 14.7 MM Btu/hr) Replaces 28MM Btu/hr boiler	PM_{10}	0.2	0.6
		SO_2	0.1	0.2
		VOC	0.1	0.4
		CO	1.3	5.6
		NO_X	1.6	6.8
43 (New)	Service Boiler #2 (natural gas, 14.7 MM Btu/hr) Replaces 28MM Btu/hr boiler	PM_{10}	0.2	
		SO_2	0.1	
		VOC	0.1	
		CO	1.3	
		NO_X	1.6	

19. At the point Alternative Scenario #2 is implemented, the permittee shall not exceed the emission rates set forth in the following table for sources SN-42 and SN-43. This replaces the emission limits specified for SN-42 & SN-43 in SC #2. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
42 (New)	Service Boiler #1 (natural gas, 14.7 MM Btu/hr)	PM	0.2	0.6
43 (New)	Service Boiler #2 (natural gas, 14.7 MM Btu/hr)	PM	0.2	

20. At the point Alternative Scenario #2 is implemented, total natural gas usage at the plant shall not exceed 562.4 million cubic feet per rolling twelve (12) month. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

21. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #20. The permittee shall update the records by the fifteenth day of the month following the month to which the records pertain. The permittee will keep the records onsite, and make the records available to Department personnel upon request. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

22. Natural gas consumption for the boilers, SN-42 and SN-43, combined, shall not exceed 11.24 MM CF per month. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

23. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #22. The permittee shall update the records by the fifteenth day of the month following the month to which the records pertain. The permittee will keep the records onsite, and make the records available to Department personnel upon request. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

24. Following implementation of Alternative Scenario #2, the permittee may apply for an administrative permit amendment to incorporate the change in boiler(s). [Regulation 18, §18.307(a), Regulation 19, §19.307 (a) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

NSPS Conditions

25. At the point either or both of the new 14.7 MM Btu/hr boilers are brought on line, the new boilers (SN-42 & SN-43) become subject to the provisions of 40 CFR Part 60, Subpart A - General Provisions and 40 CFR Part 60, Subpart Dc - *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* due to the dates of manufacture/installation. A copy of Subpart Dc is attached to this permit. [Regulation No. 19 §19.304 and 40 CFR 60, Subpart Dc]

26. The permittee shall record and maintain records of the amount of natural gas used each month on the two boilers. Compliance with this condition shall be demonstrated through Specific Condition #17 and Specific Condition #23. [Regulation No. 19 §19.705, 40 CFR §60.48c(g)(2), 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

27. All records of natural gas usage at SN-42 and SN-43 shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. [Regulation No. 19 §19.304 and 40 CFR §60.48c(i)]

Section V: INSIGNIFICANT ACTIVITIES

The Department deems the following types of activities or emissions as insignificant on the basis of size, emission rate, production rate, or activity in accordance with Group A of the Insignificant Activities list found in Regulation 18 and 19 Appendix A. Insignificant activity emission determinations rely upon the information submitted by the permittee in an application dated February 11, 2009

Description	Category
Three Zinc Quench Bath Vacuums (one, formerly SN-49), water vapor only	A-13
Four Zinc or Bezinal Quench Knives (two, formerly SN-55 and 75), water vapor only	A-13

Section VI: GENERAL CONDITIONS

1. Any terms or conditions included in this permit that 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 that 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.

2. This permit does not relieve the owner or operator of the equipment and/or the facility from compliance with all applicable provisions of the Arkansas Water and Air Pollution Control Act and the regulations promulgated under the Act. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

3. The permittee shall notify the Department in writing within thirty (30) days after commencement of construction, completion of construction, first operation of equipment and/or facility, and first attainment of the equipment and/or facility target production rate. [Regulation 19, §19.704 and/or A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

4. Construction or modification must commence within eighteen (18) months from the date of permit issuance. [Regulation 19, §19.410(B) and/or Regulation 18, §18.309(B) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

5. The permittee must keep records for five years to enable the Department to determine compliance with the terms of this permit such as hours of operation, throughput, upset conditions, and continuous monitoring data. The Department may use the records, at the discretion of the Department, to determine compliance with the conditions of the permit. [Regulation 19, §19.705 and/or Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

6. A responsible official must certify any reports required by any condition contained in this permit and submit any reports to the Department at the address below. [Regulation 19, §19.705 and/or Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

   Arkansas Department of Environmental Quality
   Air Division
   ATTN: Compliance Inspector Supervisor

5301 Northshore Drive
North Little Rock, AR 72118-5317

7. The permittee shall test any equipment scheduled for testing, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) newly constructed or 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) existing equipment already operating according to the time frames set forth by the Department. 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 must submit compliance test results to the Department within thirty (30) days after the completion of 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]

8. The permittee shall provide: [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]

   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

9. The permittee shall operate equipment, control apparatus and emission monitoring equipment within their design limitations. The permittee shall maintain in good condition at all times equipment, control apparatus and emission monitoring equipment. [Regulation 19, §19.303 and/or Regulation 18, §18.1104 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

10. If the permittee exceeds an emission limit established by this permit, the permittee will be deemed in violation of said permit and will be subject to enforcement action. The Department may forego enforcement action for emissions exceeding any limits established by this permit provided the following requirements are met: [Regulation 19, §19.601 and/or Regulation 18, §18.1101 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

   a. The permittee demonstrates to the satisfaction of the Department that the emissions resulted from an equipment malfunction or upset and are not the result of negligence or improper maintenance, and the permittee took all reasonable measures to immediately minimize or eliminate the excess emissions.
   b. The permittee reports the occurrence or upset or breakdown of equipment (by telephone, facsimile, or overnight delivery) to the Department by the end of the next business day after the occurrence or the discovery of the occurrence.
   c. The permittee must submit to the Department, within five business days after the occurrence or the discovery of the occurrence, a full, written report of such occurrence, including a statement of all known causes and of the scheduling and

nature of the actions to be taken to minimize or eliminate future occurrences, including, but not limited to, action to reduce the frequency of occurrence of such conditions, to minimize the amount by which said limits are exceeded, and to reduce the length of time for which said limits are exceeded. If the information is included in the initial report, the information need not be submitted again.

11. The permittee shall allow representatives of the Department upon the presentation of credentials: [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

    a. To enter upon the permittee's premises, or other premises under the control of the permittee, where an air pollutant source is located or in which any records are required to be kept under the terms and conditions of this permit;
    b. To have access to and copy any records required to be kept under the terms and conditions of this permit, or the Act;
    c. To inspect any monitoring equipment or monitoring method required in this permit;
    d. To sample any emission of pollutants; and
    e. To perform an operation and maintenance inspection of the permitted source.

12. The Department issued this permit in reliance upon the statements and presentations made in the permit application. The Department has no responsibility for the adequacy or proper functioning of the equipment or control apparatus. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

13. The Department may revoke or modify this permit when, in the judgment of the Department, such revocation or modification is necessary to comply with the applicable provisions of the Arkansas Water and Air Pollution Control Act and the regulations promulgated the Arkansas Water and Air Pollution Control Act. [Regulation 19, §19.410(A) and/or Regulation 18, §18.309(A) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

14. This permit may be transferred. An applicant for a transfer must submit a written request for transfer of the permit on a form provided by the Department and submit the disclosure statement required by Arkansas Code Annotated §8-1-106 at least thirty (30) days in advance of the proposed transfer date. The permit will be automatically transferred to the new permittee unless the Department denies the request to transfer within thirty (30) days of the receipt of the disclosure statement. The Department may deny a transfer on the basis of the information revealed in the disclosure statement or other investigation or, deliberate falsification or omission of relevant information. [Regulation 19, §19.407(B) and/or Regulation 18, §18.307(B) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

15. This permit shall be available for inspection on the premises where the control apparatus is located. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

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

17. This permit supersedes and voids all previously issued air permits for this facility. [Regulation 18 and 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

18. The permittee must pay all permit fees in accordance with the procedures established in Regulation No. 9. [A.C.A §8-1-105(c)]

19. 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), 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]

20. 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 facilities 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), 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]

21. 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), 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: 40 CFR Part 60, Subpart Dc - *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

Electronic Code of Federal Regulations
e-CFR ™

e-CFR Data is current as of January 12, 2010

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Browse Previous | Browse Next

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not subject by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject by this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.41c Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.* , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17) or diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 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 continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO_2control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.42c Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2emissions limit or the 90 percent SO_2reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 50 percent (0.50) of the potential SO_2emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the

heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/hr); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

E_s = SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (1.2 lb/MMBtu);

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The SO_2emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after

February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO_2 emission limits under §60.42c is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} (E_{ho}o) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted E_{ao} (E_{ao}o). The E_{ho}o is computed using the following formula:

$$E_{ho}o = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

E_{ho}o = Adjusted E_{ho}, ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0.

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO_2emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$= Potential SO_2emission rate, in percent;

$\%R_g$= SO_2removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$= SO_2removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$($\%R_g o$) is computed from $E_{ao}o$ from paragraph (e)(1) of this section and an adjusted average SO_2inlet rate ($E_{ai}o$) using the following formula:

$$\%R_g o = 100\left(1 - \frac{E^o_{ao}}{E^o_{ai}}\right)$$

Where:

$\%R_g o$ = Adjusted $\%R_g$, in percent;

$E_{ao}o$ = Adjusted E_{ao}, ng/J (lb/MMBtu); and

$E_{ai}o$ = Adjusted average SO_2inlet rate, ng/J (lb/MMBtu).

(ii) To compute $E_{ai}o$, an adjusted hourly SO_2inlet rate ($E_{hi}o$) is used. The $E_{hi}o$ is computed using the following formula:

$$E_{hi}o = \frac{E_{hi} - E_w(1 - X_1)}{X_1}$$

Where:

$E_{hi}o$ = Adjusted E_{hi}, ng/J (lb/MMBtu);

E_{hi}= Hourly SO_2inlet rate, ng/J (lb/MMBtu);

E_w= SO_2concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$; and

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A–2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A–3 of this part or 17 of appendix A–6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2or CO_2measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in theFederal Register,whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For O2 (or CO_2), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data

electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main* or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/hr).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), (f), and (g) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in §60.43c(c) and that is not required to install a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to install a COMS 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 §60.43c and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) 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.

(1) Except as provided in paragraph (a)(2) and (a)(3) 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 (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(i) 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;

(ii) 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;

(iii) 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

(iv) 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.

(2) 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 tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) 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 (a) of this section within 30 calendar days according to the requirements in §60.45c(a)(8).

(ii) 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.

(3) 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 (a)(2) 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.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in §60.43c (c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.45c(c). The CEMS specified in paragraph §60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and 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 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) 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.

(ii) 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).

(iii) 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).

(iv) 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.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit 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 steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit 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.

(4) You must record the CO measurements and calculations performed according to paragraph (e) 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.

(f) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part is not required to operate a COMS.

(g) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(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 (c)(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 (c)(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

(d) The owner or operator of each affected facility subject to the SO_2emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2or diluent (O_2or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO_2standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

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CERTIFICATE OF SERVICE

I, Cynthia Hook, hereby certify that a copy of this permit has been mailed by first class mail to Bekaert Corporation, 1881 Bekaert Drive, Van Buren, AR, 72958, on this 22nd day of January, 2010.

C Hook

Cynthia Hook, AAII, Air Division