



DIVISION OF ENVIRONMENTAL QUALITY

DRAFT MINOR SOURCE AIR PERMIT

PERMIT NUMBER: 2058-AR-10

IS ISSUED TO:

Pet Solutions Holdings, LLC
10511 Gauge Road
Danville, AR 72833
Yell County
AFIN: 75-00051

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 DIVISION OF ENVIRONMENTAL QUALITY'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. § 8-4-101 *ET SEQ.*) AND THE RULES PROMULGATED THEREUNDER, AND IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

David Witherow, P.E.
Associate Director, Office of Air Quality
Division of Environmental Quality

Date

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List of Acronyms and Abbreviations

Ark. Code Ann.	Arkansas Code Annotated
AFIN	Arkansas DEQ Facility Identification Number
C.F.R.	Code of Federal Regulations
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
HAP	Hazardous Air Pollutant
Hp	Horsepower
lb/hr	Pound Per Hour
NESHAP	National Emission Standards (for) Hazardous Air Pollutants
No.	Number
NO _x	Nitrogen Oxide
NSPS	New Source Performance Standards
PM	Particulate Matter
PM ₁₀	Particulate Matter Equal To Or Smaller Than Ten Microns
PM _{2.5}	Particulate Matter Equal To Or Smaller Than 2.5 Microns
SO ₂	Sulfur Dioxide
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

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Section I: FACILITY INFORMATION

PERMITTEE: Pet Solutions Holdings, LLC

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PERMIT NUMBER: 2058-AR-10

FACILITY ADDRESS: 10511 Gauge Road
Danville, AR 72833

MAILING ADDRESS: 10511 Gauge Road
Danville, AR 72833

COUNTY: Yell County

CONTACT NAME: Sam Lackey

CONTACT POSITION: Environmental Manager

TELEPHONE NUMBER: (479) 576-2050

REVIEWING ENGINEER: Derrick Brown

UTM North South (Y): Zone 15: 3883508.08 m

UTM East West (X): Zone 15: 482002.39 m

Section II: INTRODUCTION

Summary of Permit Activity

Pet Solutions, LLC (Pet) owns and operates a protein conversion facility located at 10511 Gauge Road, Danville, Yell County, Arkansas, southwest of Centerville and north of Ola. This modification allows the addition of a palatant flavoring line consisting of a 6 MMBtu/hr Dryer, two (2) Silos with baghouses and finished product loadout (all included in SN-19). Removal of SN-06, a 600 Hp Boiler. Finally, addition of a 4 MMBtu/hr Blood Dryer as an Insignificant Activity. This modification decreases permitted emissions by 17.7 tpy of PM₁₀, 19.0 tpy of PM, 1.4 tpy of SO₂, 0.8 tpy of VOC, 32.0 tpy of CO, 10.0 tpy of NO_x, and various HAPs.

Process Description

Pet Solutions accepts sludge from poultry producers. Sludge is defined in this permit as secondary protein nutrients (SPN) consisting of poultry solids, fats and moisture. Pet processes the SPN by dehydrating and separating it into grease/oils and protein solids utilized by the pet food industry.

Inedible Processing Lines

Blood The primary feedstock of poultry blood, feathers, and other inedible materials is trucked to the plant. After being pumped to a holding tank, the blood is sent to a coagulator and then to a mixing bin. The blood solids are separated from the “serum” liquid. The solids from the mixing bin are conveyed to a cyclone where the blood is mixed with hydrolyzed feathers prior to entering the dryer.

Feathers Upon arriving at the facility, feathers are dumped into a receiving bin. The feathers are transferred to the feather hydrolyzer, where they are heated, agitated, and reduced to wet slurry. Hydrolyzed feathers are separated from the flash vapors as they depart from the flash chamber and are mixed with blood solids in the cyclone. From the mixing bin, mixed blood and hydrolyzed feathers are transferred to the dryer (SN-09). The dryer is an ASME certified steam vessel equipped with steam discs, not direct-fired. The dryer is listed with a source number in the event AP-42 factors change in the future. The dried feather/blood meal is milled and screened before being conveyed to the storage silos.

Other Inedible Materials These materials are received and dumped into a receiving bin and transported through a metal detection and removal process to multiple horizontal, cylindrical, non-pressurized batch cookers, each equipped with a steam jacket and non-steam agitator. The steam is provided by the natural gas boilers SN-10 and SN-17. Protein solids and liquids are separated utilizing a drain pan and press. Protein solids are then ground and screened to produce a protein meal. Room air from this process is vented to the scrubber system (SN-03). Meal handling emissions from these lines are accounted for in SN-07.

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Meal and Fat Storage The meal is stored in holding bins that are located adjacent to the West load/ship-out area (SN-04). The fat from both the press and the drain pan is screened and pumped to the grease storage tanks for shipping. Both grease and bone meal are stored and shipped from the load-out area located on the southeast portion of the facility.

Palatant Line The Palatant Line (SN-19) is comprised of silos (with baghouse) for dry flavoring, a natural gas fired dryer (with baghouse), and finished product loadout. Other ingredients are produced in the existing plant and transferred to the Palatant Line in totes.

Edible Processing Lines

Edible Materials These materials are received in open top trucks, totes, and tankers. Contents of the tankers (wet product) are pumped directly to the cookers. Contents of open top trucks and totes (dry product) are received at the receiving dock and dumped into the closed raw receiving bin.

From this point, the material is transferred to the cookers in the Protein Recovery Area via a closed pipe pumping system. The Protein Recovery Area includes large capacity continuous cookers, oil separators, surge bins, screw presses, centrifuges, and coolers with bag house. The continuous cookers consist of horizontal, cylindrical, non-pressurized vessels equipped with an outer steam jacket and steam discs. The steam is provided by the natural gas boilers, SN-10 and SN-17. Vapor is vented from each cooker and routed to SN-18, SN-08, or SN-12A to remove odor prior to discharge to the atmosphere.

Materials from the cookers are dumped into one of two pre-heated closed surge bins with mixing capability and transferred to the screw presses. Solids are ground and screened to produce protein meal. The meal is stored in holding bins located adjacent to the ship-out area, SN-07, SN-13 or SN-15, after passing through the Milling/Screening Room. Fat from the press and the drain pan is processed in a centrifuge and pumped to the grease storage tanks for shipping. Both grease and bone/poultry meal are stored in silos and shipped from the load-out area.

The dry product material is transferred to a pre-heater to separate the fat, broth, and solids. The broth is transferred to an evaporator where it is concentrated. This concentrated broth is transferred to an evaporator where it is concentrated. This concentrated broth is to the dryer (SN-09) along with other solids. The dryer is not direct; steam is provided by natural gas boilers, SN-10 and SN-17. Solids are then ground and screened to produce protein. The exhaust from the evaporator and dryer are condensed. The non-condensable exhaust is then sent to a wet scrubber (SN-03). The finished product is transferred to silos. Both grease and protein are stored in silos and shipped from the load-out area.

All interior plant air will be exhausted through the wet scrubbers (SN-03, SN-08, SN-12A, and SN-12B). Blow-down water from the scrubbers is directed to the wastewater lagoons.

Miscellaneous There is a Gasoline Storage Tank SN-16 subject to 40 CFR 63 Subpart CCCCCC requirements. Pet has installed a dissolved air flotation (DAF) system as process

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equipment. The DAF process will allow Pet to recycle recoverable protein and fats from its production process.

Rules and Regulations

The following table contains the rules and regulations applicable to this permit.

Rules and Regulations
Arkansas Air Pollution Control Code, Rule 18, effective March 14, 2016
Rules of the Arkansas Plan of Implementation for Air Pollution Control, Rule 19, effective May 6, 2022
40 C.F.R. § 60.48c, Subpart Dc, <i>Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</i> , SN-10 and SN-17 (Appendix A) ¹
40 C.F.R. § 63.11110, Subpart CCCCC, <i>National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities</i> , SN-16 (Appendix C)

¹Only reporting and recordkeeping applies.

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	5.4	22.2
PM ₁₀	5.0	19.7
SO ₂	4.8	20.1
VOC	2.3	9.8
CO	14.8	64.3
NO _x	11.1	48.0
Acrolein	0.02	0.02
Arsenic	0.01	0.01
Benzene	0.03	0.03
Cadmium	0.03	0.03

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TOTAL ALLOWABLE EMISSIONS		
Pollutant	Emission Rates	
	lb/hr	tpy
Chromium, hex	0.03	0.03
Formaldehyde	0.03	0.07
Hexane	0.27	1.15
Lead	0.03	0.03
Manganese	0.03	0.03
POM/PAH	0.03	0.03
HAPs (SN-19)	0.02	0.05

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Section III: PERMIT HISTORY

Permit #2058-A (initially issued as Permit #864-A, AFIN: 75-03330) was issued to Pet Solutions, LLC on March 19, 2004. This facility was previously owned and operated by J & B Farms. In early 2002, J & B Farms ceased operation and voided the existing air permit. A new Permit Number and a new AFIN [75-00051] were issued. This permit allowed the new operator to reopen the facility and begin production. The facility was to be operated in the same manner as previously permitted without any new equipment.

Permit #2058-AR-1 (initially issued as Permit #864-1, AFIN: 75-00333) was issued to Pet Solutions, LLC on March 24, 2005. This modification removed one Natural Gas Boiler (SN-02) and installed a new Natural Gas Boiler (SN-05).

Permit #2058-AR-2 (AFIN: 75-00051) was issued to Pet Solutions, LLC on August 23, 2005. This modification permitted a 600 bhp boiler and steam turbine generator for production of electricity to be used on-site. The boiler is permitted to combust wood waste, cardboard and off-spec poultry by-products. This modification also corrected the permitted emission rates and limits in relation to natural gas boiler SN-01. The boiler permitted at heat input of 25.1 MMBtu/hr. The AFIN was changed to be the same as the ADEQ Water Division AFIN for this facility.

Permit #2058-AR-3 was issued to Pet Solutions, LLC on February 12, 2008. This permit modification authorized the following changes:

1. Remove Natural Gas Boiler SN-01 from service.
2. Install and operate 5 new cookers (will effect emissions from: SN-05 and SN-06);
3. Install additional storage bins (will effect emissions from: SN-04);
4. Install and operate meal elevators and aspirator (SN-07);
5. Include ash bin/conveyor system on the wood fired boiler (IA);
6. Include the wood chip/sawdust storage piles into the current permit (IA).
7. Allow the facility to burn landfill gas (methane) in the gas boiler.
8. Allow the close door condition to be removed for the east entrance door (process building) and the north entrance door (raw material storage building).

The overall annual permitted emissions increased 2.1 tpy PM, 1.7 tpy PM₁₀, and 30.5 tpy NO_x.

Permit #2058-AR-4 was issued to Pet Solutions, LLC on March 10, 2009. This permit modification authorized the following changes:

1. Add another wet scrubber (SN-08) to the sealed cooking process; and
2. SC #14 was revised.

The permitted emission increase due to this modification was 0.4 tons per year (tpy) VOC.

Permit #2058-AR-5 was issued to Pet Solutions, LLC on September 13, 2010. Pet Solutions requested an authorization to allow usage of Balcones fuel cubes in the Wood Fired Boiler SN-06. The total change in emissions includes an increase of 4.9 tpy VOC and 0.62 tpy Total HAPs.

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Permit #2058-AR-6 was issued to Pet Solutions, LLC on November 10, 2011. This permitting modification was necessary to:

1. Remove landfill gas as alternative fuel and remove stack test requirement at SN-05.
2. Install new 73.6 MMBtu/hr natural gas-fired, ultra-low NO_x burners, Boiler SN-10;
3. Permit SN-05, 10, 11 and 14 for natural gas combustion only;
4. Add applicable provisions of 40 CFR 60, Subpart Dc for SN-05, 06 and 10;
5. Add initial performance test for CO and NO_x hourly emissions at SN-10, SC #10;
6. Install a 5.0 and a 10.9 MMBtu/hr natural gas-fired RTOs (SN-11 and SN-14);
7. Limit Boiler SN-06 operating hours to not to exceed 7,488 hours per year;
8. Add initial performance test for PM/PM₁₀, CO and NO_x hourly emissions at SN-06, combusting wood only;
9. Clarify measurement choices of fuel usage in SN-06;
10. Require multiple cyclone fly ash arrestor to operate when SN-06 is operating;
11. Remove start-up notification of SN-06, as this requirement is complete;
12. Add applicable provisions of 40 CFR 63, Subpart JJJJJ - for Boiler SN-06, SC #21;
13. Add a work practice or management practice standard initial tune-up no later than March 21, 2012, plus biennially thereafter for Boiler SN-06;
14. Obtain a one-time energy assessment no later than March 21, 2014 for Boiler SN-06;
15. Add SN-06 recordkeeping requirements of the NCS and ACC Report;
16. Remove the meal aspirator from SN-07;
17. Revise emissions for Meal Handling based on increased throughput limit;
18. Add Load Out, Shipping and eleven Silos (SN-13) and add Meal Handling (SN-15);
19. Install three wet Scrubbers (SN-12A, 12B and 12C), add continuous monitored operating parameters and add a one-time VOC stack test of either Scrubber SN-12A, 12B or 12C;
20. Revise VOC emissions for existing Scrubbers SN-03 and 08 and add ORP monitoring;
21. Add a one-time VOC stack test for Scrubbers SN-03;
22. Clarify requirement and method to maintain negative pressure within the buildings;
23. Add two batch cookers with VOC emissions routed to RTO;
24. Add Blood/Feather Meal Process and edible Protein Processing Process. Pet will expand the existing building and reduce cookers SN-09 with emissions routed to RTO; and
25. Change the Gasoline Storage Tank from IA to SN-16 and incorporate 40 CFR 63 Subpart CCCCC requirements.

Total permitted annual emission changes associated with this modification are: 4.4 tpy PM, -0.5 tpy PM₁₀, 0.1 tpy SO₂, -0.9 tpy VOC, 6.3 tpy CO, -25.4 tpy NO_x, 0.09 tpy acetaldehyde, 0.43 tpy acrolein, 0.05 tpy arsenic, 0.49 tpy benzene, 0.05 tpy cadmium, 0.09 tpy chlorine, 0.05 tpy formaldehyde, 0.05 tpy hexavalent chromium, 2.03 tpy hydrogen chloride, 0.05 tpy lead, 0.22 tpy manganese, -0.08 tpy POM/PAH, 0.21 tpy styrene and -0.62 tpy Total HAPs.

Permit #2058-AR-7 was issued to Pet Solutions, LLC on July 19, 2012. This permitting modification was necessary to:

1. Install two new wet Scrubbers (SN-12A and 12B) with 100,000 CFM fans;
2. Remove wet Scrubber SN-12C, which was never installed, from the permit;
3. Update SC #8 to confirm notification letter dated May 3, 2012 of SN-10 Boiler;

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4. Update SC #26a to reflect requirement to conduct a tune-up of Boiler SN-06 to demonstrate initial compliance with NESHAP Subpart JJJJJ, no later than the compliance date specified in §63.11223;
5. Temporarily suspend monthly negative facility pressure monitoring, SC #34 and #35; and
6. Temporarily require daily odor monitoring at the property boundary, SC #36 and #37.

Total permitted annual emission change associated with this modification is: -0.5 tpy VOC.

Permit #2058-AR-8 was issued to Pet Solutions, LLC on January 10, 2014. This permitting modification was necessary to:

1. Remove 33.48 MMBtu/hr natural gas-fired Boiler SN-05 from service;
2. Install new 73.6 MMBtu/hr natural gas-fired Boiler SN-17, subject to 40 CFR 60 Subpart Dc, to generate steam for processes;
3. Remove RTO SN-14, which was never installed, from the permit;
4. Install 2.38 MMBtu/hr natural gas-fired Haarslev RTO SN-18 to replace RTO SN-11;
5. Remove 5.0 MMBtu/hr natural gas-fired RTO SN-11 from service, *after* installation of RTO SN-18;
6. Limit Boiler SN-06 operating hours to not to exceed 4,000 hours per year, as recorded on a non-resettable hour meter;
7. Update 40 CFR 63 Subpart JJJJJ applicable provisions for Boiler SN-06 with the promulgation of the February 1, 2013 amendments;
8. Monitoring SN-12A and 12B for pH has been removed as agreed in CAO 13-162;
9. Remove temporary property boundary odor monitoring conditions, prior SC #36 and #37, because wet scrubbers SN-12A/B installed;
10. Resume monthly interior facility pressure monitoring and recording;
11. State initial performance test of Scrubbers 03 and 12B for VOC completed;
12. State initial performance test of Boiler SN-10 for CO and NO_x completed;
13. State initial performance test of Boiler SN-06 for PM/PM₁₀, CO, and NO_x completed; and
14. Install new 1,000 gallon capacity, diesel storage tank (A-3) to IA List.

Total permitted annual emission changes associated with this modification are: -5.0 tpy (tons per year) PM, -3.5 tpy PM₁₀, 18.2 tpy SO₂, 3.4 tpy VOC, 2.5 tpy CO, 0.1 tpy NO_x, -0.09 tpy Acetaldehyde, -0.20 tpy Acrolein, -0.01 tpy Arsenic, -0.22 tpy Benzene, -0.01 tpy Cadmium, -0.04 tpy Chlorine, -0.21 tpy Formaldehyde, 1.16 tpy Hexane, -0.01 tpy Hexavalent Chromium, -0.94 tpy Hydrogen Chloride, -0.01 tpy Lead, -0.09 tpy Manganese, -0.01 tpy POM/PAH, and -0.10 tpy Styrene. The increases do not exceed the de minimis threshold levels.

Permit #2058-AR-9 was issued September 19, 2014. This permitting amendment was necessary to:

1. Add a 300-gallon mobile diesel tank to Insignificant Activities List (A-3); and
2. Correct a typo in the previous permit in the Emission Unit Summary SC #1, that SN-11 was never installed and SN-14 was removed.

There was no change in emissions.

Section IV: EMISSION UNIT INFORMATION

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. [Rule 19.501 *et seq.* and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
03	Wet Scrubber #1 (Horizontal Counter-flow, w/100,000 CFM fan, installed 1997)	VOC	0.1	0.5
04	West Load Out, Shipping & 4 Silos @ maximum 63,948 tpy	PM ₁₀	0.1	0.1
07	West Meal Handling @ maximum 63,948 tpy (Grain Elevator)	PM ₁₀	0.3	1.1
08	Wet Scrubber # 2 (25,000 CFM, installed 2008)	VOC	0.1	0.5
10	Superior Apache Firetube Boiler – Model #MS8-X-11000-5150-WBCF-G (73.6 MMBtu/hr natural gas-fired, 2200 Hp, forced draft, ultra-low NO _x , 25% flue gas recirculation, model year 2011, installed 2012)	PM ₁₀ SO ₂ VOC CO NO _x	0.6 0.1 0.4 2.7 3.0	2.5 0.3 1.8 11.7 13.0
12A	Haarslev AS100 Packed-Bed Scrubbers (w/100,000 CFM fan)	VOC	0.1	0.5
12B	Haarslev AS100 Packed-Bed Scrubbers (w/100,000 CFM fan)	VOC	0.1	0.5
13	East Load Out, Shipping and 11 Silos @ maximum 70,080 tpy (baghouse for load-out silos recirculates air back into silos)	PM ₁₀	0.1	0.1
15	East Meal Handling @ max 70,080 tpy (Enclosed Piping Sys)	PM ₁₀	0.3	1.2
16	Gasoline Storage Tank (250 gallon capacity)	VOC	0.1	0.1
17	Superior Apache Firetube Boiler – Model MS8-X-11000-8150-WBCF-G (73.6 MMBtu/hr natural gas-fired, 2200 HP, forced draft, ultra-low NO _x , 25% flue gas recirculation, installed January 8, 2014)	PM ₁₀ SO ₂ VOC CO NO _x	0.6 0.1 0.4 2.7 3.0	2.5 0.3 1.8 11.7 13.0
18	Haarslev Regenerative Thermal Oxidizer (2.38 MMBtu/hr natural gas-fired, TRO-40, installed April 29, 2014)	PM ₁₀ SO ₂ VOC	2.7 4.5 0.9	11.6 19.4 3.9

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SN	Description	Pollutant	lb/hr	tpy
		CO	8.9	38.7
		NO _x	4.5	19.4
19A	Storage Silo w/baghouse	(recirculates air back into the silos)		
19B	Storage Silo w/baghouse	(recirculates air back into the silos)		
19C	Palatant Line (6 MMBtu/hr natural gas-fired dryer, Storage Silos with baghouse (recirculates air back into the silos))	PM ₁₀	0.3	0.6
		SO ₂	0.1	0.1
		VOC	0.1	0.2
		CO	0.5	2.2
		NO _x	0.6	2.6
01, 02, 05 & 14		Removed from Service		
09	One Feather Hydrolyzer and Dryer	in-direct fired, no emissions		
11 & 12C		Never installed. Removed from permit.		

2. The permittee shall not exceed the emission rates set forth in the following table. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
04	West Load Out, Shipping & 4 Silos @ maximum 63,948 tpy	PM	0.1	0.2
07	West Meal Handling @ max 63,948 tpy (Grain Elevator)	PM	0.5	2.0
10	Superior Apache Firetube Boiler – Model #MS8-X-11000-5150-WBCF-G (73.6 MMBtu/hr natural gas-fired, 2200 Hp, forced draft, ultra-low NO _x , 25% flue gas recirculation, model year 2011, installed 2012)	PM	0.6	2.5
		Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Cadmium	0.01	0.01
		Formaldehyde	0.01	0.03
		Hexane	0.13	0.57
		Hexavalent Chromium	0.01	0.01
		Lead	0.01	0.01
		Manganese	0.01	0.01
		POM/PAH	0.01	0.01
13	East Load Out, Shipping and 11 Silos @ maximum 70,080 tpy (baghouse for load-out silos recirculates air back into silos)	PM	0.1	0.2
15	East Meal Handling @ maximum 70,080 tpy (Enclosed)	PM	0.5	2.2

SN	Description	Pollutant	lb/hr	tpy
	Piping System)			
17	Superior Apache Firetube Boiler – Model MS8-X-11000-8150-WBCF-G (73.6 MMBtu/hr natural gas-fired, 2200 HP, forced draft, ultra-low NO _x , 25% flue gas recirculation, installed January 8, 2014)	PM Arsenic Benzene Cadmium Formaldehyde Hexane Hexavalent Chromium Lead Manganese POM/PAH	0.6 0.01 0.01 0.01 0.01 0.13 0.01 0.01 0.01 0.01	2.5 0.01 0.01 0.01 0.03 0.57 0.01 0.01 0.01 0.01
18	Haarslev Regenerative Thermal Oxidizer (2.38 MMBtu/hr natural gas-fired, TRO-40, installed April 29, 2014)	PM Arsenic Benzene Cadmium Formaldehyde Hexane Hexavalent Chromium Lead Manganese POM/PAH	2.7 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01	11.6 0.01 0.01 0.01 0.01 0.02 0.01 0.01 0.01 0.01
19A	Storage Silo w/baghouse	(recirculates air back into the silos)		
19B	Storage Silo w/baghouse	(recirculates air back into the silos)		
19C	Palatant Line and 6 MMBtu/hr natural gas-fired dryer	PM HAPs	0.3 0.02	1.0 0.05

3. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Limit	Regulatory Citation
10, 17, 18 & 19	5%	§18.501 and A.C.A. (natural gas only)
04, 07, 13 & 15	5%	§18.501 and A.C.A.

4. The permittee shall not cause or permit the emission of air contaminants, including odors or water vapor and including an air contaminant whose emission is not otherwise prohibited by Rule 18, if the emission of the air contaminant constitutes air pollution within the meaning of Ark. Code Ann. § 8-4-303. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

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5. The permittee shall not conduct operations in such a manner as to unnecessarily cause air contaminants and other pollutants to become airborne. [Rule 18.901 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Natural Gas-fired Equipment – SN-10, 17, 18, and 19

6. The permittee shall use only pipeline quality natural gas as fuel in SN-10, 17, 18, and 19. Combustion emissions from all natural gas-fired equipment and boilers listed have been calculated at full load for continuous operation. Purchase receipts and/or invoices may be used along with BTU rating and operating hours to demonstrate this condition. RTO SN-18 replaced SN-14. SN-18 was installed on April 29, 2014. [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

NSPS Subpart Dc – SN-10, and 17

7. This facility is considered an affected source and Boilers SN-10, and SN-17 are subject to and must comply with the New Source Performance Standards (NSPS) 40 CFR 60 Subpart Dc - *Standards of Performance for Small Industrial- Commercial-Institutional Steam Generating Units* (Appendix A). SN-10 and 17 are each steam generating units for which construction, modification, or reconstruction commenced *after* June 9, 1989 and that have a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). [Reg.19.304 and 40 C.F.R. § 60, Subpart Dc]
8. Applicable requirements include reporting and recordkeeping provisions of §60.48c for Boilers SN-10, and 17. The permittee shall maintain a copy on site of the notification letter sent May 30, 2012 for SN-10, indicating the date of construction, anticipating startup, actual startup, as well as the design heat input capacity and fuels to be combusted. The permittee shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of Part 60 and General Condition #3 for boiler SN-17. Initial notification for SN-17 shall include items as specified in §60.48c (a). These records shall be kept at the facility in accordance with General Condition #5. [Reg.19.304 and 40 C.F.R. § 60, Subpart Dc, § 60.48c]
9. The permittee shall maintain monthly records of the individual quantity of natural gas consumed in boilers SN-10 and SN-17. This shall be achieved by either separate flow meters or as a percentage and calculation of the total natural gas consumed at the facility based on BTU rating and operating hours. Boilers SN-10 and SN-17 are identical units. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site and be made available to Department personnel upon request. Fuel usage records shall be maintained for a period of two years following the date of such records. [Reg.19.304 and 40 C.F.R. § 60.48c(g)]

10. The permittee conducted a one-time initial performance test on Boiler SN-10 on September 18, 2012 and demonstrated compliance with CO and NO_x hourly emission limits specified in Specific Condition #1. The permittee shall maintain a copy of the test results on-site in accordance with General Condition #5 and make available to Department personnel upon request. Boilers SN-10 and SN-17 are identical and the initial performance test for SN-10 shall suffice for both. If the facility conducts significant modifications to Boiler SN-10 or 17, then the facility must conduct another complete stack test on the modified boiler. [Reg.19.702 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Meal Handling and Load-out – SN-04, 07, 13, and 15

11. The permittee shall not exceed a throughput of 63,948 tons of meal production at SN-04 and SN-07 (West Meal Handling/Loadout) per rolling 12 month period. [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
12. The permittee shall not exceed a throughput of 70,080 tons of meal production at SN-13 and SN-15 (East Meal Handling/Loadout) per rolling 12 month period. [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
13. The permittee shall process poultry by-products and other acceptable food by-products at the facility, except as stated in this condition. The permittee may also process whole hogs, which must be processed immediately upon arrival unless the whole hogs are stored under refrigeration. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
14. The permittee shall maintain monthly records to demonstrate compliance with Specific Conditions #29, #30, and #31. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site and be made available to Department personnel upon request. [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
15. All raw materials received at the facility shall be placed inside a process building immediately or shall not be stored outside for a period longer than 18 hours, unless this material is stored under refrigeration. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Scrubbers – SN-03, 08, 12A, and 12B

16. The SN-03, 08, 12A, and 12B scrubbers shall be kept in good working condition, shall operate continuously whenever their respective areas and/or lines are operating and shall be monitored to meet the following operating limits: [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Control Equipment and Air Flow	Parameter	Operating Limits Per Manufacturer's Specification and Design
03	Wet Scrubber #1 with 100,000 CFM fan	ORP	Minimum 200 mV
08	Wet Scrubber #2 with 25,000 CFM fan	ORP	Minimum 200 mV
12A & 12B	Two Haarslev Scrubbers with 100,000 CFM fans (for each unit)	ORP	Minimum 200 mV
		Inlet Gas Temperature	Maximum 100°F

- a. The permittee shall install, maintain, and operate an Oxidation Reduction Potential (ORP) monitor or equivalent measuring device with data logger or other recording device to continuously measure and record the ORP of scrubbers SN-03, 08, 12A, and 12B. Each ORP monitor shall automatically alarm if the ORP falls below the minimum 200 millivolt (mV) level.
 - b. The permittee shall install, maintain, and operate a temperature gauge with data logger or other recording device to continuously measure and record the inlet gas temperature to scrubbers SN-12A and 12B. Each temperature monitor shall automatically alarm if the temperature exceeds the maximum temperature of 100°F.

35. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #34. The permittee shall maintain the Material Safety Data Sheets (MSDS) or equivalent documentation of the scrubber oxidizing agent. The requirement for continuous measurement and recording of the ORP of existing scrubbers SN-03 and SN-08 has been demonstrated complete. The permittee shall record each failure/alarm on an as-occurred basis and shall include scrubber source number and description, date, time, shift, type of parameter failure/alarm, cause(s), method(s) of resolution, and operator name/initial. The permittee shall maintain these records for two years. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. These records shall be maintained in a well-organized monthly format by source number, maintained on site and shall be made available to Department personnel upon request. [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

36. The permittee conducted an initial performance test on scrubber SN-12B on September 18, 2012 and successfully demonstrated compliance with VOC hourly emission limits specified in Specific Condition #1. Scrubbers SN-12A and 12B are identical and one test sufficed for both. The permittee shall maintain a copy of the test results on-site in accordance with General Condition #5 and make available to Department personnel upon request. No further performance test of SN-12A and 12B is required unless the facility

conducts significant modifications or changes to operating parameters to SN-12A and 12B, then the facility must conduct another test. [Reg.19.702 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

37. The permittee conducted an initial performance test on scrubber SN-03 on May 9, 2012 and successfully demonstrated compliance with VOC hourly emission limits specified in Specific Condition #1. The permittee shall maintain a copy of the test results on-site in accordance with General Condition #5 and make available to Department personnel upon request. No further performance test of SN-03 is required unless the facility conducts significant modifications or changes to operating parameters to SN-03, then the facility must conduct another test. No initial performance test is required for scrubber SN-08. [Reg.19.702 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Negative Facility Air Pressure Monitoring

38. The permittee shall maintain a negative pressure inside all distinct areas of the process building at all times. All containers and holding bins for raw materials and finished product shall be kept in closed containers at all times, except for normal processing. The permittee must perform housekeeping measures (sweep or vacuum process areas) to minimize odors, including but not limited to spill clean-up as expeditiously as practicable. All doors, windows and other openings shall be kept closed except for the following: [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- a. Process Building – Doors, windows and other openings may be kept open if SN-03, 08, 12A and 12B wet scrubbers are all operating properly. All distinct areas of the process building must be under negative pressure, as determined by outside air flowing into the structure and a once monthly pressure test per Specific Condition #39.
 - b. Raw Material Storage Building – All doors, windows and other openings shall be kept closed/shut except during normal ingress and egress, as practicable, except for the North entrance door to this building.
39. To demonstrate compliance with Specific Condition #38, the permittee shall test and record the Process Building interior air pressure at least once monthly. The test shall be performed in numerous areas, as appropriate to sufficiently cover the entire building. This test shall consist of a smoke test, anemometer or other test to demonstrate that the airflow is into the building at all openings except the scrubber discharges. If positive pressure is detected at any location, the permittee shall immediately take action to identify the cause of the positive pressure, implement corrective action, and document that the building pressure complies with the permitted negative pressure following the corrective action. The permittee shall maintain these records for three years. These records shall be updated on an as-performed basis, maintained on site, and made available to Department

personnel upon request. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

NESHAP Subpart CCCCCC Conditions – SN-16

40. The permittee shall not exceed a throughput of 15,000 gallons of gasoline at storage tank SN-16 per rolling 12-month period. The permittee shall not exceed a throughput of 10,000 gallons of gasoline per individual month. [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
41. The permittee shall maintain documentation (e.g., purchase orders or receipts) and monthly records which demonstrate compliance with Specific Condition #40. Material Data Safety Sheets or other equivalent documents shall be maintained on-site and made available upon request. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site and made available to Department personnel upon request. Records shall be kept for a period of five years. [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
42. The permittee is subject to and shall comply with the applicable provisions of 40 CFR Part 63, Subpart CCCCCC – *National Emission standards for Hazardous Air Pollutants for Gasoline Dispensing Facilities* (Appendix C). *Gasoline dispensing facility (GDF)* is defined in §63.11132 as any stationary facility which dispenses gasoline into the fuel tank of a motor vehicle, motor vehicle engine, nonroad vehicle, or nonroad engine, including a nonroad vehicle or nonroad engine used solely for competition. Pet Solutions, an area source, is a GDF. The affected source includes each gasoline cargo tank during the delivery of product to a GDF and also includes each storage tank. SN-16 is an existing affected source to which this subpart applies. Pet must comply with the standards in 40 CFR 63 Subpart CCCCCC no later than January 10, 2011. [Reg.19.304 and 40 C.F.R. § 63, Subpart CCCCCC]
43. The permittee must comply with the requirements in §63.11116 because it has a monthly throughput of less than 10,000 gallons of gasoline. Requirements for facilities with monthly throughput of less than 10,000 gallons of gasoline are as follows:
 - a. The permittee must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:
 - i. Minimize gasoline spills;
 - ii. Clean up spills as expeditiously as practicable;
 - iii. Cover all open gasoline containers and all gasoline storage tanks fill-pipes with a gasketed seal when not in use; and

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- iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.
 - b. The permittee is not required to submit notifications or reports as specified in §63.11125, §63.11126, or subpart A of Part 63, but the permittee must have records available within 24 hours of a request by the Department to document your gasoline throughput.
 - c. The permittee must comply with the requirements of 40 CFR 63 Subpart CCCCCC by the applicable dates specified in §63.11113.
 - d. Portable gasoline containers that meet the requirements of 40 CFR Part 59, subpart F, are considered acceptable for compliance with this.
- [Reg.19.304 and 40 C.F.R. § 63.11111(b) and § 63.11116(a) through (d)]

Palatant Line – SN-19

- 44. The permittee shall not produce more than 26,280 tons of final product from SN-19 per rolling 12 month period. [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- 45. The permittee shall maintain monthly records to demonstrate compliance with Condition #44. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site and made available to Division of Environmental Quality personnel upon request. [Reg.19.705 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

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Section V: INSIGNIFICANT ACTIVITIES

The Division of Environmental Quality 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 Rule 18 and Rule 19 Appendix A. Group B insignificant activities may be listed but are not required to be listed in permits. Insignificant activity emission determinations rely upon the information submitted by the permittee in an application dated December 8, 2021. [Rule 19.408 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Description	Category
One 1,200 gallon Diesel Storage Tank	A-3
One 640 gallon Diesel Storage Tank	A-3
One 1,000 gallon Diesel Storage Tank	A-3
One 300 gallon capacity mobile diesel tank	A-3
4 MMBtu/hr Blood Dryer	A-1

Section VI: GENERAL CONDITIONS

1. Any terms or conditions included in this permit that specify and reference Arkansas Pollution Control & Ecology Commission Rule 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 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 Rule 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*). Any terms or conditions included in this permit that specify and reference Arkansas Pollution Control & Ecology Commission Rule 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 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 rules promulgated under the Act. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
3. The permittee shall notify the Division of Environmental Quality in writing within thirty (30) days after each of the following events: 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. [Rule 19.704 and/or Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
4. Construction or modification must commence within eighteen (18) months from the date of permit issuance. [Rule 19.410(B) and/or Rule 18.309(B) and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
5. The permittee must keep records for five years to enable the Division of Environmental Quality to determine compliance with the terms of this permit such as hours of operation, throughput, upset conditions, and continuous monitoring data. The Division of Environmental Quality may use the records, at the discretion of the Division of Environmental Quality, to determine compliance with the conditions of the permit. [Rule 19.705 and/or Rule 18.1004 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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 Division of Environmental Quality electronically using <https://portal.adeg.state.ar.us> or mail them to the address below. [Rule 19.705 and/or Rule 18.1004 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

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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 Division of Environmental Quality. The permittee must notify the Division of Environmental Quality of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee must submit compliance test results to the Division of Environmental Quality within sixty (60) calendar days after the completion of testing. [Rule 19.702 and/or Rule 18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
8. The permittee shall provide: [Rule 19.702 and/or Rule 18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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. [Rule 19.303 and/or Rule 18.1104 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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 Division of Environmental Quality may forego enforcement action for emissions exceeding any limits established by this permit provided the following requirements are met: [Rule 19.601 and/or Rule 18.1101 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
 - a. The permittee demonstrates to the satisfaction of the Division of Environmental Quality 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, overnight delivery, or online at <https://portal.adeg.state.ar.us>) to the Division of Environmental Quality by the

- end of the next business day after the occurrence or the discovery of the occurrence.
- c. The permittee must submit to the Division of Environmental Quality, 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 Division of Environmental Quality upon the presentation of credentials: [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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 Division of Environmental Quality issued this permit in reliance upon the statements and presentations made in the permit application. The Division of Environmental Quality has no responsibility for the adequacy or proper functioning of the equipment or control apparatus. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
 13. The Division of Environmental Quality may revoke or modify this permit when, in the judgment of the Division of Environmental Quality, such revocation or modification is necessary to comply with the applicable provisions of the Arkansas Water and Air Pollution Control Act and the rules promulgated the Arkansas Water and Air Pollution Control Act. [Rule 19.410(A) and/or Rule 18.309(A) and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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 Division of Environmental Quality 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 Division of Environmental Quality denies the request to transfer within thirty (30) days of the receipt of the

disclosure statement. The Division of Environmental Quality 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. [Rule 19.407(B) and/or Rule 18.307(B) and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

15. This permit shall be available for inspection on the premises where the control apparatus is located. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
16. This permit authorizes only those pollutant emitting activities addressed herein. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
17. This permit supersedes and voids all previously issued air permits for this facility. [Rule 18 and/or Rule 19 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
18. The permittee must pay all permit fees in accordance with the procedures established in Rule 9. [Ark. Code Ann. § 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 Division of Environmental Quality approval. The Division of Environmental Quality 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.

[Rule 18.314(A) and/or Rule 19.416(A), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 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 Division of Environmental Quality approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Division of Environmental Quality 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;

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- d. The request contains such information necessary for the Division of Environmental Quality 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.

[Rule 18.314(B) and/or Rule 19.416(B), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 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 Division of Environmental Quality approval. The Division of Environmental Quality 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.

[Rule 18.314(C) and/or Rule 19.416(C), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

22. Any credible evidence based on sampling, monitoring, and reporting may be used to determine violations of applicable emission limitations. [Rule 18.1001, Rule 19.701, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

APPENDIX A

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/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).
- (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 (SO₂) 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) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion 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, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)
- (f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or [subpart CCCC of this part](#) is not subject to this subpart.
- (g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing [subpart BBBB of this part](#) is not subject to this subpart.
- (h) Affected facilities that also meet the applicability requirements under subpart J or [subpart Ja of this part](#) are subject to the PM and NO_x standards under this subpart and the SO₂ standards under subpart J or [subpart Ja of this part](#), as applicable.
- (i) Temporary boilers are not subject to this subpart.

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5090](#), Jan. 28, 2009; [77 FR 9461](#), Feb. 16, 2012]

§ 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.

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 hydrosulfurization 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](#)), 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](#)), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see [§ 60.17](#)), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see [§ 60.17](#)), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see [§ 60.17](#)).

Dry flue gas desulfurization technology means a SO₂ control 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 SO₂ control 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 SO₂ emissions (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.

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO₂ emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
- (4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology means an SO₂ control 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 SO₂.

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; [77 FR 9461](#), Feb. 16, 2012]

§ 60.42c Standard for sulfur dioxide (SO₂).

(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 SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected

facility any gases that contain SO₂ in 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 SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in 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 SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of SO₂ in 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 SO₂ emissions limit or the 90 percent SO₂ reduction 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 SO₂ emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 50 percent (0.50) of the potential SO₂ emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in 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 SO₂ reduction 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 SO₂ in 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/h) 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; or

(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 SO₂ in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; 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 SO₂ in excess of the following:

(1) The percent of potential SO₂ emission rate or numerical SO₂ 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/h); 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 = SO₂ 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 SO₂ 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 SO₂ emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO₂ 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 \(h\)\(1\), \(2\), \(3\), or \(4\)](#) 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 affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO₂ emission 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; [77 FR 9462](#), Feb. 16, 2012]

[§ 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/h) 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/h) 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 combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) 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 \(c\)](#).

(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/h) 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/h) 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) 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 SO₂ 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; 77 FR 9462, Feb. 16, 2012]

§ 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 SO₂ 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 SO₂ emission limits under [§ 60.42c](#) is based on the average percent reduction and the average SO₂ 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 SO₂ 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 SO₂ emission rate (E_{ho}) and the 30-day average SO₂ 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 SO₂ emission rate, ng/J (lb/MMBtu);

E_w = SO₂ 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_2 emission 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_2 emission 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_2 emission rate, in percent;

$\%R_g$ = SO_2 removal efficiency of the control device as determined by Method 19 of [appendix A of this part](#), in percent; and

$\%R_f$ = SO_2 removal 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_2 inlet rate ($E_{ai,o}$) using the following formula:

$$\%R_{g,o} = 100 \left(1 - \frac{E_{ao,o}}{E_{ai,o}} \right)$$

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_2 inlet rate, ng/J (lb/MMBtu).

(ii) To compute $E_{ai,o}$, an adjusted hourly SO₂ inlet rate ($E_{hi,o}$) is used. The $E_{hi,o}$ is computed using the following formula:

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

Where:

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

E_{hi} = Hourly SO₂ inlet rate, ng/J (lb/MMBtu);

E_w = SO₂ concentration 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 SO₂ 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 SO₂ 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 SO₂ 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 (O₂) or carbon dioxide (CO₂) 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 O₂ or CO₂ measurements 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 O₂ (or CO₂) 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) For O₂ (or CO₂), 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) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in [§ 60.8](#), conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) ([see http://www.epa.gov/ttn/chief/ert/ert_tool.html/](http://www.epa.gov/ttn/chief/ert/ert_tool.html/)) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(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/h).

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5091](#), Jan. 28, 2009; [76 FR 3523](#), Jan. 20, 2011; [77 FR 9463](#), Feb. 16, 2012]

[§ 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 SO₂ emission limits under [§ 60.42c](#) shall install, calibrate, maintain, and operate a CEMS for measuring SO₂ concentrations and either O₂ or CO₂ concentrations at the outlet of the SO₂ control device (or the outlet of the steam generating unit if no SO₂ 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 SO₂ concentrations and either O₂ or CO₂ concentrations at both the inlet and outlet of the SO₂ control device.

(b) The 1-hour average SO₂ 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 SO₂ 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 SO₂ 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 SO₂ CEMS at the inlet to the SO₂ control device shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted, and the span value of the SO₂ CEMS at the outlet from the SO₂ control device shall be 50 percent of the maximum estimated hourly potential SO₂ 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 SO₂ CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under [paragraph \(a\)](#) of this section, an owner or operator may elect to determine the average SO₂ emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under [paragraph \(a\)](#) of this section, an owner or operator may elect to determine the average SO₂ 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 to 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 SO₂ 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 SO₂ at the inlet or outlet of the SO₂ 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 SO₂ and CO₂ 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 SO₂ 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 \(c\), \(d\), \(e\), and \(f\)](#) 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\(c\)](#) that is not required to use a COMS due to [paragraphs \(c\), \(d\), \(e\), or \(f\)](#) of this section that elects not to use 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](#) by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either [paragraphs \(a\)\(1\), \(a\)\(2\), or \(a\)\(3\)](#) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(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 within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; 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 45 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 45 calendar days according to the requirements in [§ 60.45c\(a\)\(8\)](#).

(ii) If no visible emissions are observed for 10 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, SO₂, 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) An owner or operator of an affected facility that is subject to an opacity standard in [§ 60.43c\(c\)](#) is not required to operate a COMS provided that the affected facility meets the conditions in either [paragraphs \(f\)\(1\), \(2\), or \(3\)](#) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section [§ 60.48Da of this part](#).

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section [§ 60.48Da of this part](#).

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. 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. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the

notification and reporting requirements specified in [§§ 60.8](#) and [60.11](#) that the owner or operator submit any deviations with the excess emissions report required under [§ 60.48c\(c\)](#).

[[72 FR 32759](#), June 13, 2007, as amended at [74 FR 5091](#), Jan. 28, 2009; [76 FR 3523](#), Jan. 20, 2011; [77 FR 9463](#), Feb. 16, 2012]

[§ 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 SO₂ 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 SO₂ 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 SO₂ emission 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 SO₂ emission 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 SO₂ emission 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 SO₂ emission 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 SO₂ or diluent (O₂ or CO₂) 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 SO₂ standard, 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 SO₂ standard, 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]

APPENDIX B

[Subpart JJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources](#)

Source: [76 FR 15591](#), Mar. 21, 2011, unless otherwise noted.

[What This Subpart Covers](#)

[§ 63.11193 Am I subject to this subpart?](#)

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in [§ 63.11237](#) that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in [§ 63.2](#), except as specified in [§ 63.11195](#).

[§ 63.11194 What is the affected source of this subpart?](#)

- (a) This subpart applies to each new, reconstructed, or existing affected source as defined in [paragraphs \(a\)\(1\) and \(2\)](#) of this section.
- (1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers within a subcategory, as listed in [§ 63.11200](#) and defined in [§ 63.11237](#), located at an area source.
- (2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler within a subcategory, as listed in [§ 63.11200](#) and as defined in [§ 63.11237](#), located at an area source.
- (b) An affected source is an existing source if you commenced construction or reconstruction of the affected source on or before June 4, 2010.
- (c) An affected source is a new source if you commenced construction of the affected source after June 4, 2010, and the boiler meets the applicability criteria at the time you commence construction.
- (d) An affected source is a reconstructed source if the boiler meets the reconstruction criteria as defined in [§ 63.2](#), you commenced reconstruction after June 4, 2010, and the boiler meets the applicability criteria at the time you commence reconstruction.
- (e) An existing dual-fuel fired boiler meeting the definition of gas-fired boiler, as defined in [§ 63.11237](#), that meets the applicability requirements of this subpart after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel.
- (f) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under [40 CFR part 70](#) or part 71 as a result of this subpart. You may, however, be required to obtain a title V permit due to another reason or reasons. *See* [40 CFR 70.3\(a\) and \(b\)](#) or [71.3\(a\) and \(b\)](#). Notwithstanding the exemption from title V permitting for area sources under this subpart, you must continue to comply with the provisions of this subpart.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7506](#), Feb. 1, 2013]

[§ 63.11195 Are any boilers not subject to this subpart?](#)

The types of boilers listed in [paragraphs \(a\) through \(k\)](#) of this section are not subject to this subpart and to any requirements in this subpart.

- (a) Any boiler specifically listed as, or included in the definition of, an affected source in another standard(s) under this part.
- (b) Any boiler specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act.
- (c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by [subpart EEE of this part](#) (e.g., hazardous waste boilers).
- (d) A boiler that is used specifically for research and development. This exemption does not include boilers that solely or primarily provide steam (or heat) to a process or for heating at a research and development facility. This exemption does not prohibit the use of the steam (or heat) generated from the boiler during research and development, however, the boiler must be concurrently and primarily engaged in research and development for the exemption to apply.
- (e) A gas-fired boiler as defined in this subpart.
- (f) A hot water heater as defined in this subpart.
- (g) Any boiler that is used as a control device to comply with another subpart of this [part](#), or [part 60](#), [part 61](#), or [part 65 of this chapter](#) provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler is provided by regulated gas streams that are subject to another standard.
- (h) Temporary boilers as defined in this subpart.
- (i) Residential boilers as defined in this subpart.
- (j) Electric boilers as defined in this subpart.
- (k) An electric utility steam generating unit (EGU) as defined in this subpart.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7506](#), Feb. 1, 2013; [81 FR 63125](#), Sept. 14, 2016]

[§ 63.11196 What are my compliance dates?](#)

- (a) If you own or operate an existing affected boiler, you must achieve compliance with the applicable provisions in this subpart as specified in [paragraphs \(a\)\(1\) through \(3\)](#) of this section.
 - (1) If the existing affected boiler is subject to a work practice or management practice standard of a tune-up, you must achieve compliance with the work practice or management practice standard no later than March 21, 2014.
 - (2) If the existing affected boiler is subject to emission limits, you must achieve compliance with the emission limits no later than March 21, 2014.
 - (3) If the existing affected boiler is subject to the energy assessment requirement, you must achieve compliance with the energy assessment requirement no later than March 21, 2014.
- (b) If you start up a new affected source on or before May 20, 2011, you must achieve compliance with the provisions of this subpart no later than May 20, 2011.
- (c) If you start up a new affected source after May 20, 2011, you must achieve compliance with the provisions of this subpart upon startup of your affected source.

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in [§ 63.11195\(b\)](#) for commercial and industrial solid waste incineration units covered by [40 CFR part 60, subpart CCCC](#) or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the waste to fuel switch as specified in [§ 60.2145\(a\)\(2\)](#) and [\(3\)](#) of subpart CCCC or [§ 60.2710\(a\)\(2\)](#) and [\(3\)](#) of subpart DDDD.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7506](#), Feb. 1, 2013]

Emission Limits, Work Practice Standards, Emission Reduction Measures, and Management Practices

§ 63.11200 What are the subcategories of boilers?

The subcategories of boilers, as defined in [§ 63.11237](#) are:

- (a) Coal.
- (b) Biomass.
- (c) Oil.
- (d) Seasonal boilers.
- (e) Oil-fired boilers with heat input capacity of equal to or less than 5 million British thermal units (Btu) per hour.
- (f) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.
- (g) Limited-use boilers.

[[78 FR 7506](#), Feb. 1, 2013]

§ 63.11201 What standards must I meet?

- (a) You must comply with each emission limit specified in Table 1 to this subpart that applies to your boiler.
- (b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in Table 2 to this subpart satisfies the energy assessment requirement. A facility that operates under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected units, also satisfies the energy assessment requirement.
- (c) You must comply with each operating limit specified in Table 3 to this subpart that applies to your boiler.
- (d) These standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in [§ 63.11237](#), during which time you must comply only with Table 2 to this subpart.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7506](#), Feb. 1, 2013]

General Compliance Requirements

§ 63.11205 What are my general requirements for complying with this subpart?

(a) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or a continuous monitoring system (CMS), including a continuous emission monitoring system (CEMS), a continuous opacity monitoring system (COMS), or a continuous parameter monitoring system (CPMS), where applicable. You may demonstrate compliance with the applicable mercury emission limit using fuel analysis if the emission rate calculated according to [§ 63.11211\(c\)](#) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of CPMS), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in [paragraphs \(c\)\(1\) through \(3\)](#) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under [§ 63.8\(f\)](#).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses [paragraphs \(c\)\(1\)\(i\) through \(vi\)](#) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to [part 60 of this chapter](#) and that meet the requirements of [§ 63.11224](#).

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).

(iv) Ongoing operation and maintenance procedures in accordance with the general requirements of [§ 63.8\(c\)\(1\)\(ii\)](#), [\(c\)\(3\)](#), and [\(c\)\(4\)\(ii\)](#);

(v) Ongoing data quality assurance procedures in accordance with the general requirements of [§ 63.8\(d\)](#); and

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of [§ 63.10\(c\)](#) (as applicable in Table 8 to this subpart), [\(e\)\(1\)](#), and [\(e\)\(2\)\(i\)](#).

(2) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(3) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7506](#), Feb. 1, 2013]

[Initial Compliance Requirements](#)

§ 63.11210 What are my initial compliance requirements and by what date must I conduct them?

- (a) You must demonstrate initial compliance with each emission limit specified in Table 1 to this subpart that applies to you by either conducting performance (stack) tests, as applicable, according to [§ 63.11212](#) and Table 4 to this subpart or, for mercury, conducting fuel analyses, as applicable, according to [§ 63.11213](#) and Table 5 to this subpart.
- (b) For existing affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after the compliance date that is specified in [§ 63.11196](#) and according to the applicable provisions in [§ 63.7\(a\)\(2\)](#), except as provided in [paragraph \(k\)](#) of this section.
- (c) For existing affected boilers that have applicable work practice standards, management practices, or emission reduction measures, you must demonstrate initial compliance no later than the compliance date that is specified in [§ 63.11196](#) and according to the applicable provisions in [§ 63.7\(a\)\(2\)](#), except as provided in [paragraph \(j\)](#) of this section.
- (d) For new or reconstructed affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after March 21, 2011 or within 180 days after startup of the source, whichever is later, according to [§ 63.7\(a\)\(2\)\(ix\)](#).
- (e) For new or reconstructed oil-fired boilers that commenced construction or reconstruction on or before September 14, 2016, that combust 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 particulate matter (PM) emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce PM or sulfur dioxide emissions, you are not subject to the PM emission limit in Table 1 of this subpart until September 14, 2019, providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel. On and after September 14, 2019, you are subject to the PM emission limit in Table 1 of this subpart and you must demonstrate compliance with the PM emission limit in Table 1 no later than March 12, 2020.
- (f) For new or reconstructed boilers that combust only ultra-low-sulfur liquid fuel as defined in [§ 63.11237](#), you are not subject to the PM emission limit in Table 1 of this subpart providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in [§ 63.11237](#), you must conduct a performance test within 60 days of burning the new fuel.
- (g) For new or reconstructed affected boilers that have applicable work practice standards or management practices, you are not required to complete an initial performance tune-up, but you are required to complete the applicable biennial or 5-year tune-up as specified in [§ 63.11223](#) no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed affected source.
- (h) For affected boilers that ceased burning solid waste consistent with [§ 63.11196\(d\)](#) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch as specified in [§ 60.2145\(a\)\(2\)](#) and [\(3\)](#) of subpart CCCC or [§ 60.2710\(a\)\(2\)](#) and [\(3\)](#) of subpart DDDD. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.
- (i) For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within subpart JJJJJ or the boiler becoming subject to subpart JJJJJ, you must demonstrate compliance within 180 days of the effective date of the fuel switch or the physical change. Notification of such changes must be submitted according to [§ 63.11225\(g\)](#).

(j) For boilers located at existing major sources of HAP that limit their potential to emit (*e.g.*, make a physical change or take a permit limit) such that the existing major source becomes an area source, you must comply with the applicable provisions as specified in [paragraphs \(j\)\(1\) through \(3\)](#) of this section.

(1) Any such existing boiler at the existing source must demonstrate compliance with subpart JJJJJ within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source.

(2) Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJ within 180 days of the later of March 21, 2011 or startup.

(3) Notification of such changes must be submitted according to [§ 63.11225\(g\)](#).

(k) For existing affected boilers that have not operated on solid fossil fuel, biomass, or liquid fuel between the effective date of the rule and the compliance date that is specified for your source in [§ 63.11196](#), you must comply with the applicable provisions as specified in [paragraphs \(k\)\(1\) through \(3\)](#) of this section.

(1) You must complete the initial compliance demonstration, if subject to the emission limits in Table 1 to this subpart, as specified in [paragraphs \(a\) and \(b\)](#) of this section, no later than 180 days after the re-start of the affected boiler on solid fossil fuel, biomass, or liquid fuel and according to the applicable provisions in [§ 63.7\(a\)\(2\)](#).

(2) You must complete the initial performance tune-up, if subject to the tune-up requirements in [§ 63.11223](#), by following the procedures described in [§ 63.11223\(b\)](#) no later than 30 days after the re-start of the affected boiler on solid fossil fuel, biomass, or liquid fuel.

(3) You must complete the one-time energy assessment, if subject to the energy assessment requirements specified in Table 2 to this subpart, no later than the compliance date specified in [§ 63.11196](#).

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7507](#), Feb. 1, 2013; [81 FR 63125](#), Sept. 14, 2016]

[§ 63.11211 How do I demonstrate initial compliance with the emission limits?](#)

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to [§ 63.11212](#) and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to [§ 63.11213](#) and Table 5 to this subpart, establishing operating limits according to [§ 63.11222](#), Table 6 to this subpart and [paragraph \(b\)](#) of this section, as applicable, and conducting CMS performance evaluations according to [§ 63.11224](#). For affected boilers that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under [§ 63.11213](#) and Table 5 to this subpart.

(b) You must establish parameter operating limits according to [paragraphs \(b\)\(1\) through \(4\)](#) of this section.

(1) For a wet scrubber, you must establish the minimum scrubber liquid flow rate and minimum scrubber pressure drop as defined in [§ 63.11237](#), as your operating limits during the three-run performance stack test. If you use a wet scrubber and you conduct separate performance stack tests for PM and mercury emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance stack tests, you must set the minimum scrubber liquid flow rate and pressure drop operating limits at the highest minimum values established during the performance stack tests.

(2) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum total secondary electric power (secondary voltage and secondary current), as defined in [§ 63.11237](#), as your operating limits during the three-run performance stack test.

(3) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in [§ 63.11237](#), as your operating limit during the three-run performance stack test.

(4) The operating limit for boilers with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in [§ 63.11224](#), and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(c) If you elect to demonstrate compliance with an applicable mercury emission limit through fuel analysis, you must conduct fuel analyses according to [§ 63.11213](#) and Table 5 to this subpart and follow the procedures in [paragraphs \(c\)\(1\)](#) through [\(3\)](#) of this section.

(1) If you burn more than one fuel type, you must determine the fuel type, or mixture, you could burn in your boiler that would result in the maximum emission rates of mercury.

(2) You must determine the 90th percentile confidence level fuel mercury concentration of the composite samples analyzed for each fuel type using Equation 1 of this section.

$$P_{90} = \text{mean} + (\text{SD} * t) \quad (\text{Eq. 1})$$

Where:

P_{90} = 90th percentile confidence level mercury concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel mercury concentration in the fuel samples analyzed according to [§ 63.11213](#), in units of pounds per million Btu.

SD = Standard deviation of the mercury concentration in the fuel samples analyzed according to [§ 63.11213](#), in units of pounds per million Btu.

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable mercury emission limit, the emission rate that you calculate for your boiler using Equation 1 of this section must be less than the applicable mercury emission limit.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7508](#), Feb. 1, 2013]

[§ 63.11212 What stack tests and procedures must I use for the performance tests?](#)

(a) You must conduct all performance tests according to [§ 63.7\(c\)](#), [\(d\)](#), [\(f\)](#), and [\(h\)](#). You must also develop a site-specific test plan according to the requirements in [§ 63.7\(c\)](#).

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart. Boilers that use a CEMS for carbon monoxide (CO) are exempt from the initial CO performance testing in Table 4 to this subpart and the oxygen concentration operating limit requirement specified in Table 3 to this subpart.

(c) You must conduct performance stack tests at the representative operating load conditions while burning the type of fuel or mixture of fuels that have the highest emissions potential for each regulated pollutant, and you must demonstrate initial compliance and establish your operating limits based on these performance stack tests. For subcategories with more than one emission limit, these requirements could result in the need to conduct more than one performance stack test. Following each performance stack test and until the next performance stack test, you must comply with the operating limit for operating load conditions specified in Table 3 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance stack test required in this section, as specified in [§ 63.7\(e\)\(3\)](#) and in accordance with the provisions in Table 4 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A-7 to [part 60 of this chapter](#) to convert the measured PM concentrations and the measured mercury concentrations that result from the performance test to pounds per million Btu heat input emission rates.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7508](#), Feb. 1, 2013]

[§ 63.11213 What fuel analyses and procedures must I use for the performance tests?](#)

(a) You must conduct fuel analyses according to the procedures in [paragraphs \(b\)](#) and [\(c\)](#) of this section and Table 5 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury in Table 1 of this subpart.

(b) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in Table 5 to this subpart. Each composite sample must consist of a minimum of three samples collected at approximately equal intervals during a test run period.

(c) Determine the concentration of mercury in the fuel in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 5 to this subpart.

[§ 63.11214 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?](#)

(a) If you own or operate an existing or new coal-fired boiler with a heat input capacity of less than 10 million Btu per hour, you must conduct a performance tune-up according to [§ 63.11210\(c\)](#) or [\(g\)](#), as applicable, and [§ 63.11223\(b\)](#). If you own or operate an existing coal-fired boiler with a heat input capacity of less than 10 million Btu per hour, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted an initial tune-up of the boiler.

(b) If you own or operate an existing or new biomass-fired boiler or an existing or new oil-fired boiler, you must conduct a performance tune-up according to [§ 63.11210\(c\)](#) or [\(g\)](#), as applicable, and [§ 63.11223\(b\)](#). If you own or operate an existing biomass-fired boiler or existing oil-fired boiler, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted an initial tune-up of the boiler.

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed according to Table 2 to this subpart and that the assessment is an accurate depiction of your facility at the time of the assessment or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

(d) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7508](#), Feb. 1, 2013; [81 FR 63126](#), Sept. 14, 2016]

Continuous Compliance Requirements

§ 63.11220 When must I conduct subsequent performance tests or fuel analyses?

(a) If your boiler has a heat input capacity of 10 million Btu per hour or greater, you must conduct all applicable performance (stack) tests according to [§ 63.11212](#) on a triennial basis, except as specified in [paragraphs \(b\) through \(e\)](#) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test.

(b) For new or reconstructed boilers that commenced construction or reconstruction on or before September 14, 2016, when demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you do not need to conduct further performance tests for PM until September 14, 2021, but must continue to comply with all applicable operating limits and monitoring requirements and must comply with the provisions as specified in [paragraphs \(b\)\(1\) through \(4\)](#) of this section.

(1) A performance test for PM must be conducted by September 14, 2021.

(2) If your performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you may choose to conduct performance tests for PM every fifth year. Each such performance test must be conducted no more than 61 months after the previous performance test.

(3) If you intend to burn a new type of fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in [§ 63.11237](#), you must conduct a performance test within 60 days of burning the new fuel type.

(4) If your performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests on a triennial basis as specified in [paragraph \(a\)](#) of this section.

(c) For new or reconstructed boilers that commenced construction or reconstruction after September 14, 2016, when demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you may choose to conduct performance tests for PM every fifth year, but must continue to comply with all applicable operating limits and monitoring requirements and must comply with the provisions as specified in [paragraphs \(c\)\(1\) through \(3\)](#) of this section.

(1) Each such performance test must be conducted no more than 61 months after the previous performance test.

(2) If you intend to burn a new type of fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in [§ 63.11237](#), you must conduct a performance test within 60 days of burning the new fuel type.

(3) If your performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests on a triennial basis as specified in [paragraph \(a\)](#) of this section.

(d) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to [§ 63.11213](#) for each type of fuel burned as specified in [paragraphs \(d\)\(1\) through \(3\)](#) of this section. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of [§ 63.11211](#). The recalculated mercury emission rate must be less than the applicable emission limit.

(1) For existing boilers and new or reconstructed boilers that commenced construction or reconstruction on or before September 14, 2016, when demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you do not need to conduct further fuel analysis sampling until September 14, 2017, but must continue to comply with all applicable operating limits and monitoring requirements and must comply with the provisions as specified in [paragraphs \(d\)\(1\)\(i\) and \(ii\)](#) of this section.

(i) Fuel analysis sampling for mercury must be conducted by September 14, 2017.

(ii) If your fuel analysis results show that the mercury constituents in the fuel or fuel mixture are equal to or less than half of the mercury emission limit, you may choose to conduct fuel analysis sampling for mercury every 12 months.

(2) For new or reconstructed boilers that commenced construction or reconstruction after September 14, 2016, when demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you may choose to conduct fuel analysis sampling for mercury every 12 months, but must continue to comply with all applicable operating limits and monitoring requirements.

(3) When demonstrating compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are greater than half of the mercury emission limit, you must conduct quarterly sampling.

(e) For existing affected boilers that have not operated on solid fossil fuel, biomass, or liquid fuel since the previous compliance demonstration and more than 3 years have passed since the previous compliance demonstration, you must complete your subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler on solid fossil fuel, biomass, or liquid fuel.

[\[81 FR 63127, Sept. 14, 2016\]](#)

[§ 63.11221 Is there a minimum amount of monitoring data I must obtain?](#)

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by [§ 63.11205\(c\)](#).

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating and compliance is required, except for periods of monitoring system malfunctions or out-of-control periods (see [§ 63.8\(c\)\(7\) of this part](#)), repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data collected during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or quality control activities in calculations used to report emissions or operating levels. Any such periods must be reported according to the requirements in [§ 63.11225](#). You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan), failure to collect required data is a deviation of the monitoring requirements.

[78 FR 7508, Feb. 1, 2013, as amended at [81 FR 63127](#), Sept. 14, 2016]

[§ 63.11222 How do I demonstrate continuous compliance with the emission limits?](#)

(a) You must demonstrate continuous compliance with each emission limit and operating limit in Tables 1 and 3 to this subpart that applies to you according to the methods specified in Table 7 to this subpart and to [paragraphs \(a\)\(1\) through \(4\)](#) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under [§§ 63.7](#) and [63.11196](#), whichever date comes first, you must continuously monitor the operating parameters. Operation above the established maximum, below the established minimum, or outside the allowable range of the operating limits specified in [paragraph \(a\)](#) of this section constitutes a deviation from your operating limits established under this subpart, except during performance tests conducted to determine compliance with the emission and operating limits or to establish new operating limits. Operating limits are confirmed or reestablished during performance tests.

(2) If you have an applicable mercury or PM emission limit, you must keep records of the type and amount of all fuels burned in each boiler during the reporting period. If you have an applicable mercury emission limit, you must demonstrate that all fuel types and mixtures of fuels burned would result in lower emissions of mercury than the applicable emission limit (if you demonstrate compliance through fuel analysis), or result in lower fuel input of mercury than the maximum values calculated during the last performance stack test (if you demonstrate compliance through performance stack testing).

(3) If you have an applicable mercury emission limit and you plan to burn a new type of fuel, you must determine the mercury concentration for any new fuel type in units of pounds per million Btu, using the procedures in Equation 1 of [§ 63.11211](#) based on supplier data or your own fuel analysis, and meet the requirements in [paragraphs \(a\)\(3\)\(i\) or \(ii\)](#) of this section.

(i) The recalculated mercury emission rate must be less than the applicable emission limit.

(ii) If the mercury concentration is higher than mercury fuel input during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in [§ 63.11212](#) to demonstrate that the mercury emissions do not exceed the emission limit.

(4) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective

action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm is counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time is counted as the actual amount of time taken to initiate corrective action.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 and 3 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in [§ 63.11225](#).

[[76 FR 15591](#), Mar. 21, 2011, as amended at [81 FR 63127](#), Sept. 14, 2016]

[§ 63.11223 How do I demonstrate continuous compliance with the work practice and management practice standards?](#)

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a performance tune-up according to [paragraph \(b\)](#) of this section and keep records as required in [§ 63.11225\(c\)](#) to demonstrate continuous compliance. You must conduct the tune-up while burning the type of fuel (or fuels in the case of boilers that routinely burn two types of fuels at the same time) that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

(b) Except as specified in [paragraphs \(c\)](#) through [\(f\)](#) of this section, you must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in [paragraphs \(b\)\(1\)](#) through [\(7\)](#) of this section. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed boiler, the first biennial tune-up must be no later than 25 months after the initial startup of the new or reconstructed boiler.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection.

(2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection.

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject.

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in [paragraphs \(b\)\(6\)\(i\)](#) through [\(iii\)](#) of this section.

- (i) The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler.
- (ii) A description of any corrective actions taken as a part of the tune-up of the boiler.
- (iii) The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.
- (7) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.
- (c) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up must conduct a tune-up of the boiler every 5 years as specified in [paragraphs \(b\)\(1\) through \(7\)](#) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed boiler with an oxygen trim system, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in [paragraph \(b\)\(1\)](#) of this section and inspection of the system controlling the air-to-fuel ratio specified in [paragraph \(b\)\(3\)](#) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.
- (d) Seasonal boilers must conduct a tune-up every 5 years as specified in [paragraphs \(b\)\(1\) through \(7\)](#) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed seasonal boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in [paragraph \(b\)\(1\)](#) of this section and inspection of the system controlling the air-to-fuel ratio specified in [paragraph \(b\)\(3\)](#) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Seasonal boilers are not subject to the emission limits in Table 1 to this subpart or the operating limits in Table 3 to this subpart.
- (e) Oil-fired boilers with a heat input capacity of equal to or less than 5 million Btu per hour must conduct a tune-up every 5 years as specified in [paragraphs \(b\)\(1\) through \(7\)](#) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed oil-fired boiler with a heat input capacity of equal to or less than 5 million Btu per hour, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in [paragraph \(b\)\(1\)](#) of this section and inspection of the system controlling the air-to-fuel ratio specified in [paragraph \(b\)\(3\)](#) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.
- (f) Limited-use boilers must conduct a tune-up every 5 years as specified in [paragraphs \(b\)\(1\) through \(7\)](#) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed limited-use boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in [paragraph \(b\)\(1\)](#) of this section and inspection of the system controlling the air-to-fuel ratio specified in [paragraph \(b\)\(3\)](#) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Limited-use boilers are not subject to the emission limits in Table 1 to this subpart, the energy assessment requirements in Table 2 to this subpart, or the operating limits in Table 3 to this subpart.
- (g) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If

manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7509, Feb. 1, 2013; 81 FR 63127, Sept. 14, 2016]

§ 63.11224 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler is subject to a CO emission limit in Table 1 to this subpart, you must either install, operate, and maintain a CEMS for CO and oxygen according to the procedures in [paragraphs \(a\)\(1\) through \(6\)](#) of this section, or install, calibrate, operate, and maintain an oxygen analyzer system, as defined in [§ 63.11237](#), according to the manufacturer's recommendations and [paragraphs \(a\)\(7\) and \(d\)](#) of this section, as applicable, by the compliance date specified in [§ 63.11196](#). Where a certified CO CEMS is used, the CO level shall be monitored at the outlet of the boiler, after any add-on controls or flue gas recirculation system and before release to the atmosphere. Boilers that use a CO CEMS are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in [§ 63.11211\(a\) of this subpart](#). Oxygen monitors and oxygen trim systems must be installed to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location.

(1) Each CO CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification 4, 4A, or 4B at [40 CFR part 60, appendix B](#), and each oxygen CEMS must be installed, operated, and maintained according to Performance Specification 3 at [40 CFR part 60, appendix B](#). Both the CO and oxygen CEMS must also be installed, operated, and maintained according to the site-specific monitoring plan developed according to [paragraph \(c\)](#) of this section.

(2) You must conduct a performance evaluation of each CEMS according to the requirements in [§ 63.8\(e\)](#) and according to Performance Specifications 3 and 4, 4A, or 4B at [40 CFR part 60, appendix B](#).

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) every 15 minutes. You must have CEMS data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in [§ 63.8\(g\)\(2\)](#).

(5) You must calculate hourly averages, corrected to 3 percent oxygen, from each hour of CO CEMS data in parts per million CO concentrations and determine the 10-day rolling average of all recorded readings, except as provided in [§ 63.11221\(c\)](#). Calculate a 10-day rolling average from all of the hourly averages collected for the 10-day operating period using Equation 2 of this section.

$$\text{10-day average} = \frac{\sum_{i=1}^n Hpvi}{n} \quad (\text{Eq. 2})$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 10 boiler operating days

(6) For purposes of collecting CO data, you must operate the CO CEMS as specified in [§ 63.11221\(b\)](#). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in [§ 63.11221\(c\)](#). Periods when CO data are unavailable may constitute monitoring deviations as specified in [§ 63.11221\(d\)](#).

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.

(b) If you are using a control device to comply with the emission limits specified in Table 1 to this subpart, you must maintain each operating limit in Table 3 to this subpart that applies to your boiler as specified in Table 7 to this subpart. If you use a control device not covered in Table 3 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under [§ 63.8\(f\)](#).

(c) If you demonstrate compliance with any applicable emission limit through stack testing and subsequent compliance with operating limits, you must develop a site-specific monitoring plan according to the requirements in [paragraphs \(c\)\(1\)](#) through [\(4\)](#) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under [§ 63.8\(f\)](#).

(1) For each CMS required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses [paragraphs \(c\)\(1\)\(i\)](#) through [\(iii\)](#) of this section. You must submit this site-specific monitoring plan (if requested) at least 60 days before your initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(2) In your site-specific monitoring plan, you must also address [paragraphs \(c\)\(2\)\(i\)](#) through [\(iii\)](#) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of [§ 63.8\(c\)\(1\)](#), [\(3\)](#), and [\(4\)\(ii\)](#).

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of [§ 63.8\(d\)](#).

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of [§ 63.10\(c\)](#), [\(e\)\(1\)](#), and [\(e\)\(2\)\(i\)](#).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each CPMS according to the procedures in [paragraphs \(d\)\(1\)](#) through [\(4\)](#) of this section.

(1) The CPMS must complete a minimum of one cycle of operation every 15 minutes. You must have data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(2) You must calculate hourly arithmetic averages from each hour of CPMS data in units of the operating limit and determine the 30-day rolling average of all recorded readings, except as provided in [§ 63.11221\(c\)](#). Calculate a 30-day rolling average from all of the hourly averages collected for the 30-day operating period using Equation 3 of this section.

$$\text{30-day average} = \frac{\sum_{i=1}^n Hpvi}{n} \quad (\text{Eq. 3})$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 30 boiler operating days

(3) For purposes of collecting data, you must operate the CPMS as specified in [§ 63.11221\(b\)](#). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in [§ 63.11221\(c\)](#). Periods when CPMS data are unavailable may constitute monitoring deviations as specified in [§ 63.11221\(d\)](#).

(4) Record the results of each inspection, calibration, and validation check.

(e) If you have an applicable opacity operating limit under this rule, you must install, operate, certify and maintain each COMS according to the procedures in [paragraphs \(e\)\(1\) through \(8\)](#) of this section by the compliance date specified in [§ 63.11196](#).

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 of [40 CFR part 60, appendix B](#).

(2) You must conduct a performance evaluation of each COMS according to the requirements in [§ 63.8](#) and according to Performance Specification 1 of [40 CFR part 60, appendix B](#).

(3) As specified in [§ 63.8\(c\)\(4\)\(i\)](#), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in [§ 63.8\(g\)\(2\)](#).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in [§ 63.8\(d\)](#). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of [§ 63.8\(e\)](#). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must calculate and record 6-minute averages from the opacity monitoring data and determine and record the daily block average of recorded readings, except as provided in [§ 63.11221\(c\)](#).

(8) For purposes of collecting opacity data, you must operate the COMS as specified in [§ 63.11221\(b\)](#). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in [§ 63.11221\(c\)](#). Periods when COMS data are unavailable may constitute monitoring deviations as specified in [§ 63.11221\(d\)](#).

(f) If you use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in [paragraphs \(f\)\(1\) through \(8\)](#) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with EPA-454/R-98-015 (incorporated by reference, see [§ 63.14](#)).

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an audible or visual alarm system that will activate automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard or seen by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments or cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7510](#), Feb. 1, 2013]

[§ 63.11225 What are my notification, reporting, and recordkeeping requirements?](#)

(a) You must submit the notifications specified in [paragraphs \(a\)\(1\) through \(5\)](#) of this section to the administrator.

(1) You must submit all of the notifications in [§§ 63.7\(b\); 63.8\(e\) and \(f\); and 63.9\(b\) through \(e\), \(g\), and \(h\)](#) that apply to you by the dates specified in those sections except as specified in [paragraphs \(a\)\(2\) and \(4\)](#) of this section.

(2) An Initial Notification must be submitted no later than January 20, 2014 or within 120 days after the source becomes subject to the standard.

(3) If you are required to conduct a performance stack test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance stack test is scheduled to begin.

(4) You must submit the Notification of Compliance Status no later than 120 days after the applicable compliance date specified in [§ 63.11196](#) unless you own or operate a new boiler subject only to a requirement to conduct a

biennial or 5-year tune-up or you must conduct a performance stack test. If you own or operate a new boiler subject to a requirement to conduct a tune-up, you are not required to prepare and submit a Notification of Compliance Status for the tune-up. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of completing the performance stack test. You must submit the Notification of Compliance Status in accordance with [paragraphs \(a\)\(4\)\(i\)](#) and [\(vi\)](#) of this section. The Notification of Compliance Status must include the information and certification(s) of compliance in [paragraphs \(a\)\(4\)\(i\)](#) through [\(v\)](#) of this section, as applicable, and signed by a responsible official.

(i) You must submit the information required in [§ 63.9\(h\)\(2\)](#), except the information listed in [§ 63.9\(h\)\(2\)\(i\)\(B\)](#), [\(D\)](#), [\(E\)](#), and [\(F\)](#). If you conduct any performance tests or CMS performance evaluations, you must submit that data as specified in [paragraph \(e\)](#) of this section. If you conduct any opacity or visible emission observations, or other monitoring procedures or methods, you must submit that data to the Administrator at the appropriate address listed in [§ 63.13](#).

(ii) “This facility complies with the requirements in [§ 63.11214](#) to conduct an initial tune-up of the boiler.”

(iii) “This facility has had an energy assessment performed according to [§ 63.11214\(c\)](#).”

(iv) For units that install bag leak detection systems: “This facility complies with the requirements in [§ 63.11224\(f\)](#).”

(v) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: “No secondary materials that are solid waste were combusted in any affected unit.”

(vi) The notification must be submitted electronically using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written Notification of Compliance Status must be submitted to the Administrator at the appropriate address listed in [§ 63.13](#).

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must include in the Notification of Compliance Status the date of the test and a summary of the results, not a complete test report, relative to this subpart.

(b) You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in [paragraphs \(b\)\(1\)](#) through [\(4\)](#) of this section. You must submit the report by March 15 if you had any instance described by [paragraph \(b\)\(3\)](#) of this section. For boilers that are subject only to the energy assessment requirement and/or a requirement to conduct a biennial or 5-year tune-up according to [§ 63.11223\(a\)](#) and not subject to emission limits or operating limits, you may prepare only a biennial or 5-year compliance report as specified in [paragraphs \(b\)\(1\)](#) and [\(2\)](#) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with the official's name, title, phone number, email address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart. Your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) “This facility complies with the requirements in [§ 63.11223](#) to conduct a biennial or 5-year tune-up, as applicable, of each boiler.”

(ii) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: “No secondary materials that are solid waste were combusted in any affected unit.”

(iii) “This facility complies with the requirement in [§§ 63.11214\(d\)](#) and [63.11223\(g\)](#) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.”

(3) If the source experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken.

(4) The total fuel use by each affected boiler subject to an emission limit, for each calendar month within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by you or EPA through a petition process to be a non-waste under [§ 241.3\(c\)](#), whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of [§ 241.3](#), and the total fuel usage amount with units of measure.

(c) You must maintain the records specified in [paragraphs \(c\)\(1\)](#) through [\(7\)](#) of this section.

(1) As required in [§ 63.10\(b\)\(2\)\(xiv\)](#), you must keep a copy of each notification and report that you submitted to comply with this subpart and all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted.

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by [§ 63.11214](#) and [§ 63.11223](#) as specified in [paragraphs \(c\)\(2\)\(i\)](#) through [\(vi\)](#) of this section.

(i) Records must identify each boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.

(ii) For operating units that combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to [§ 241.3\(b\)\(1\) of this chapter](#), you must keep a record which documents how the secondary material meets each of the legitimacy criteria under [§ 241.3\(d\)\(1\)](#). If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to [§ 241.3\(b\)\(4\) of this chapter](#), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in [§ 241.2](#) and each of the legitimacy criteria in [§ 241.3\(d\)\(1\) of this chapter](#). If the fuel received a non-waste determination pursuant to the petition process submitted under [§ 241.3\(c\) of this chapter](#), you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per [§ 241.4](#), you must keep records documenting that the material is a listed non-waste under [§ 241.4\(a\)](#).

(iii) For each boiler required to conduct an energy assessment, you must keep a copy of the energy assessment report.

(iv) For each boiler subject to an emission limit in Table 1 to this subpart, you must keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used. For each new oil-fired boiler that meets the requirements of [§ 63.11210\(e\)](#) or [\(f\)](#), you must keep records, on a monthly basis, of the type of fuel combusted.

(v) For each boiler that meets the definition of seasonal boiler, you must keep records of days of operation per year.

(vi) For each boiler that meets the definition of limited-use boiler, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and records of fuel use for the days the boiler is operating.

(3) For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation that were done to demonstrate compliance with the mercury emission limits. Supporting documentation should include results of any fuel analyses. You can use the results from one fuel analysis for multiple boilers provided they are all burning the same fuel type.

(4) Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in [§ 63.11205\(a\)](#), including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(6) You must keep the records of all inspection and monitoring data required by [§§ 63.11221](#) and [63.11222](#), and the information identified in [paragraphs \(c\)\(6\)\(i\)](#) through [\(vi\)](#) of this section for each required inspection or monitoring.

(i) The date, place, and time of the monitoring event.

(ii) Person conducting the monitoring.

(iii) Technique or method used.

(iv) Operating conditions during the activity.

(v) Results, including the date, time, and duration of the period from the time the monitoring indicated a problem to the time that monitoring indicated proper operation.

(vi) Maintenance or corrective action taken (if applicable).

(7) If you use a bag leak detection system, you must keep the records specified in [paragraphs \(c\)\(7\)\(i\)](#) through [\(iii\)](#) of this section.

(i) Records of the bag leak detection system output.

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings.

(iii) The date and time of all bag leak detection system alarms, and for each valid alarm, the time you initiated corrective action, the corrective action taken, and the date on which corrective action was completed.

(d) Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on-site or be accessible from a central location by computer or other means that instantly provide access at the site for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years.

(e)

(1) Within 60 days after the date of completing each performance test (as defined in [§ 63.2](#)) required by this subpart, you must submit the results of the performance tests, including any associated fuel analyses, following the procedure specified in either [paragraph \(e\)\(1\)\(i\)](#) or [\(ii\)](#) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (https://www3.epa.gov/ttn/chief/ert/ert_info.html) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>.) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in [§ 63.13](#).

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in [§ 63.2](#)), you must submit the results of the performance evaluation following the procedure specified in either [paragraph \(e\)\(2\)\(i\)](#) or [\(ii\)](#) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being submitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in [§ 63.13](#).

(f) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(g) If you have switched fuels or made a physical change to the boiler and the fuel switch or change resulted in the applicability of a different subcategory within this subpart, in the boiler becoming subject to this subpart, or in the boiler switching out of this subpart due to a fuel change that results in the boiler meeting the definition of gas-fired boiler, as defined in [§ 63.11237](#), or you have taken a permit limit that resulted in you becoming subject to this subpart or no longer being subject to this subpart, you must provide notice of the date upon which you switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that have switched fuels, were physically changed, or took a permit limit, and the date of the notice.

(2) The date upon which the fuel switch, physical change, or permit limit occurred.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7511](#), Feb. 1, 2013; [81 FR 63127](#), Sept. 14, 2016]

§ 63.11226 [Reserved]

Other Requirements and Information

§ 63.11235 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in [§§ 63.1](#) through [63.15](#) apply to you.

§ 63.11236 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA or an administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under [40 CFR part 63, subpart E](#), the authorities contained in [paragraphs \(c\)](#) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency.

(c) The authorities that cannot be delegated to state, local, or tribal agencies are specified in [paragraphs \(c\)\(1\)](#) through [\(5\)](#) of this section.

(1) Approval of an alternative non-opacity emission standard and work practice standards in [§ 63.11223\(a\)](#).

(2) Approval of alternative opacity emission standard under [§ 63.6\(h\)\(9\)](#).

(3) Approval of major change to test methods under [§ 63.7\(e\)\(2\)\(ii\)](#) and [\(f\)](#). A “major change to test method” is defined in [§ 63.90](#).

(4) Approval of a major change to monitoring under [§ 63.8\(f\)](#). A “major change to monitoring” is defined in [§ 63.90](#).

(5) Approval of major change to recordkeeping and reporting under [§ 63.10\(f\)](#). A “major change to recordkeeping/reporting” is defined in [§ 63.90](#).

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7513](#), Feb. 1, 2013]

§ 63.11237 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in [§ 63.2](#) (the General Provisions), and in this section as follows:

10-day rolling average means the arithmetic mean of all valid hours of data from 10 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

30-day rolling average means the arithmetic mean of all valid hours of data from 30 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

Annual capacity factor means the ratio between the actual heat input to a boiler from the fuels burned during a calendar year and the potential heat input to the boiler had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see [§ 63.14](#)).

Biomass means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and wood products (*e.g.*, trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.*, almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

Biomass subcategory includes any boiler that burns any biomass and is not in the coal subcategory.

Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in [§ 241.3 of this chapter](#), is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler*.

Boiler system means the boiler and associated components, such as, feedwater systems, combustion air systems, fuel systems (including burners), blowdown systems, combustion control systems, steam systems, and condensate return systems, directly connected to and serving the energy use systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388 (incorporated by reference, see [§ 63.14](#)), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of “coal” includes synthetic fuels derived from coal including, but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal subcategory includes any boiler that burns any solid fossil fuel and no more than 15 percent biomass on an annual heat input basis.

Commercial boiler means a boiler used in commercial establishments such as hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown and periods when the unit is not operating.

Deviation

(1) Means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see [§ 63.14](#)) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see [§ 63.14](#)), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see [§ 63.14](#)).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers are included in this definition. A dry scrubber is a dry control system.

Electric boiler means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.*, coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2015.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers with less than 0.3 trillion Btu per year (TBtu/year) heat input capacity will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (*e.g.*, steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour energy assessment.

(2) The energy assessment for facilities with affected boilers with 0.3 to 1.0 TBtu/year heat input capacity will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the affected boiler(s) energy (*e.g.*, steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour energy assessment.

(3) The energy assessment for facilities with affected boilers with greater than 1.0 TBtu/year heat input capacity will be up to 24 on-site technical labor hours in length for the first TBtu/year plus 8 on-site technical labor hours for every additional 1.0 TBtu/year not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy (*e.g.*, steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use system(s) serving as the basis for the percent of affected boiler(s) energy production, as applicable, in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (*e.g.*, product X manufacturing area; product Y drying area; Building Z).

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system

(1) Includes the following systems located on the site of the affected boiler that use energy provided by the boiler:

(i) Process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting; or

(ii) Other systems that use steam, hot water, process heat, or electricity, provided by the affected boiler.

(2) Energy use systems are only those systems using energy clearly produced by affected boilers.

Equivalent means the following only as this term is used in Table 5 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or

EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining mercury using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing this metal. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the mercury concentration mathematically adjusted to a dry basis.

(6) An equivalent mercury determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for mercury and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 5 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of [40 CFR parts 60, 61, 63, and 65](#), requirements within any applicable state implementation plan, and any permit requirements established under [40 CFR 52.21](#) or under [40 CFR 51.18](#) and [40 CFR 51.24](#).

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuels includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas.

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or for periodic testing, maintenance, or operator training on liquid fuel. Periodic testing, maintenance, or operator training on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Heat input means heat derived from combustion of fuel in a boiler and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass fuel and hot water is withdrawn for use external to the vessel. Hot water boilers (*i.e.*, not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 million Btu per hour heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on-demand hot water.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Institutional boiler means a boiler used in institutional establishments such as, but not limited to, medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, and governmental buildings to provide electricity, steam, and/or hot water.

Limited-use boiler means any boiler that burns any amount of solid or liquid fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil meeting the specification in [40 CFR 279.11](#), liquid biofuels, biodiesel, and vegetable oil.

Load fraction means the actual heat input of a boiler divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (*e.g.*, for 50 percent load the load fraction is 0.5). For boilers that co-fire natural gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (*e.g.*, if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas, the load fraction is 0.5).

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable carbon monoxide emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average scrubber liquid flow rate (*e.g.*, to the particulate matter scrubber) measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

- (1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits; or
- (2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

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 gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see [§ 63.14](#)); or
- (3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions (*i.e.*, a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals). Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or
- (4) Propane or propane-derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C₃H₈.

Oil subcategory includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel only during periods of gas curtailment, gas supply interruptions, startups, or for periodic testing are not included in this definition. Periodic testing on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

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

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller or draft controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Performance testing means the collection of data resulting from the execution of a test method used (either by stack testing or fuel analysis) to demonstrate compliance with a relevant emission standard.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Regulated gas stream means an offgas stream that is routed to a boiler for the purpose of achieving compliance with a standard under another subpart of this [part](#) or [part 60](#), [part 61](#), or [part 65 of this chapter](#).

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (*e.g.*, university campus, military base, church grounds) or commercial/industrial facility (*e.g.*, farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families, or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

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 of Testing and Materials in ASTM D396-10 (incorporated by reference, see [§ 63.14\(b\)](#)).

Responsible official means responsible official as defined in [§ 70.2](#).

Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

Shutdown means the period in which cessation of operation of a boiler is initiated for any purpose. Shutdown begins when the boiler no longer supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, or when no fuel is being fed to the boiler, whichever is earlier. Shutdown ends when the boiler no longer supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, and no fuel is being combusted in the boiler.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire-derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means:

(1) Either the first-ever firing of fuel in a boiler for the purpose of supplying useful thermal energy (such as steam or hot water) for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the useful thermal energy (such as steam or hot water) from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler for the purpose of supplying useful thermal energy (such as steam or hot water) for heating, cooling or process purposes or producing electricity, or the firing of fuel in a boiler for any purpose after a shutdown event. Startup ends 4 hours after when the boiler supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, whichever is earlier.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
- (4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Tune-up means adjustments made to a boiler in accordance with the procedures outlined in [§ 63.11223\(b\)](#).

Ultra-low-sulfur liquid fuel means a distillate oil that has less than or equal to 15 parts per million (ppm) sulfur.

Useful thermal energy means energy (*i.e.*, steam or hot water) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler.

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards (VCS) mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, +61 2 9237 6171 <http://www.standards.org.au>), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, <http://www.bsigroup.com>), Canadian Standards Association (CSA, 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, <http://www.csa.ca>), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, <http://www.cen.eu/cen>), and German Engineering Standards (VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, <http://www.vdi.eu>). The types of standards that are not considered VCS are standards developed by: the United States, *e.g.*, California Air Resources Board (CARB) and Texas Commission on Environmental Quality (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. Government, *e.g.*, Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (*i.e.*, hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (*e.g.*, thermal oxidizer, kiln, furnace) or power (*e.g.*, combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to section 112(h) of the Clean Air Act.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7513](#), Feb. 1, 2013; [81 FR 63128](#), Sept. 14, 2016]

Table 1 to Subpart JJJJJ of Part 63 - Emission Limits

As stated in [§ 63.11201](#), you must comply with the following applicable emission limits:

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
1. New coal-fired boilers with heat input capacity of 30 million British thermal units per hour (MMBtu/hr) or greater that do not meet the definition of limited-use boiler	a. PM (Filterable) b. Mercury c. CO	3.0E-02 pounds(lb) per million British thermal units (MMBtu) of heat input. 2.2E-05 lb per MMBtu of heat input. 420 parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
2. New coal-fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of limited-use boiler	a. PM (Filterable) b. Mercury c. CO	4.2E-01 lb per MMBtu of heat input. 2.2E-05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
3. New biomass-fired boilers with heat input capacity of 30 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	3.0E-02 lb per MMBtu of heat input.
4. New biomass fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	7.0E-02 lb per MMBtu of heat input.
5. New oil-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	3.0E-02 lb per MMBtu of heat input.

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
6. Existing coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of limited-use boiler	<ul style="list-style-type: none"> a. Mercury b. CO 	<ul style="list-style-type: none"> 2.2E-05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).

[78 FR 7517, Feb. 1, 2013, as amended at 81 FR 63130, Sept. 14, 2016]

Table 2 to Subpart JJJJJ of Part 63 - Work Practice Standards, Emission Reduction Measures, and Management Practices

As stated in § 63.11201, you must comply with the following applicable work practice standards, emission reduction measures, and management practices:

If your boiler is in this subcategory . . .	You must meet the following . . .
1. Existing or new coal-fired, new biomass-fired, or new oil-fired boilers (units with heat input capacity of 10 MMBtu/hr or greater)	Minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.
2. Existing coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
3. New coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
4. Existing oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
5. New oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or	Conduct a tune-up of the boiler biennially as specified in § 63.11223.

If your boiler is in this subcategory . . .	You must meet the following . . .
limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	
6. Existing biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in § 63.11214 , and conduct a tune-up of the boiler biennially as specified in § 63.11223 .
7. New biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in § 63.11223 .
8. Existing seasonal boilers	Conduct an initial tune-up as specified in § 63.11214 , and conduct a tune-up of the boiler every 5 years as specified in § 63.11223 .
9. New seasonal boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223 .
10. Existing limited-use boilers	Conduct an initial tune-up as specified in § 63.11214 , and conduct a tune-up of the boiler every 5 years as specified in § 63.11223 .
11. New limited-use boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223 .
12. Existing oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct an initial tune-up as specified in § 63.11214 , and conduct a tune-up of the boiler every 5 years as specified in § 63.11223 .
13. New oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223 .
14. Existing coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up	Conduct an initial tune-up as specified in § 63.11214 , and conduct a tune-up of the boiler every 5 years as specified in § 63.11223 .
15. New coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223 .

If your boiler is in this subcategory . . .	You must meet the following . . .
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<p>biennial tune-up</p> <p>16. Existing coal-fired, biomass-fired, or oil-fired boilers (units with heat input capacity of 10 MMBtu/hr and greater), not including limited-use boilers</p>	<p>Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table satisfies the energy assessment requirement. Energy assessor approval and qualification requirements are waived in instances where past or amended energy assessments are used to meet the energy assessment requirements. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least 1 year between January 1, 2008, and the compliance date specified in § 63.11196 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items (1) to (4) appropriate for the on-site technical hours listed in § 63.11237:</p> <ol style="list-style-type: none"> (1) A visual inspection of the boiler system, (2) An evaluation of operating characteristics of the affected boiler systems, specifications of energy use systems, operating and maintenance procedures, and unusual operating constraints, (3) An inventory of major energy use systems consuming energy from affected boiler(s) and which are under control of the boiler owner or operator, (4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage, (5) A list of major energy conservation measures that are within the facility's control, (6) A list of the energy savings potential of the energy conservation measures identified, and (7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
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[[78 FR 7518](#), Feb. 1, 2013, as amended at [81 FR 63129](#), Sept. 14, 2016]

[Table 3 to Subpart JJJJJ of Part 63 - Operating Limits for Boilers With Emission Limits](#)

As stated in [§ 63.11201](#), you must comply with the applicable operating limits:

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits except during periods of startup and shutdown . . .
1. Fabric filter control	<p>a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR</p> <p>b. Install and operate a bag leak detection system according to § 63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.</p>
2. Electrostatic precipitator control	<p>a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR</p> <p>b. Maintain the 30-day rolling average total secondary electric power of the electrostatic precipitator at or above the minimum total secondary electric power as defined in § 63.11237.</p>
3. Wet scrubber control	<p>Maintain the 30-day rolling average pressure drop across the wet scrubber at or above the minimum scrubber pressure drop as defined in § 63.11237 and the 30-day rolling average liquid flow rate at or above the minimum scrubber liquid flow rate as defined in § 63.11237.</p>
4. Dry sorbent or activated carbon injection control	<p>Maintain the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent injection rate or minimum activated carbon injection rate as defined in § 63.11237. When your boiler operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (<i>e.g.</i>, actual heat input divided by the heat input during the performance stack test; for 50 percent load, multiply the injection rate operating limit by 0.5).</p>
5. Any other add-on air pollution control type.	<p>This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).</p>
6. Fuel analysis	<p>Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rate calculated according to § 63.11211(c) are less than the applicable emission limit for mercury.</p>
7. Performance stack testing	<p>For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.</p>
8. Oxygen analyzer system	<p>For boilers subject to a CO emission limit that demonstrate compliance with an oxygen analyzer system as specified in § 63.11224(a), maintain the 30-day rolling average oxygen level at or above the minimum oxygen level as defined in § 63.11237. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7).</p>

[78 FR 7519, Feb. 1, 2013]

[Table 4 to Subpart JJJJJJ of Part 63 - Performance \(Stack\) Testing Requirements](#)

As stated in [§ 63.11212](#), you must comply with the following requirements for performance (stack) test for affected sources:

To conduct a performance test for the following pollutant. . .	You must. . .	Using. . .
1. Particulate Matter	<p>a. Select sampling ports location and the number of traverse points</p> <p>b. Determine velocity and volumetric flow-rate of the stack gas</p> <p>c. Determine oxygen and carbon dioxide concentrations of the stack gas</p> <p>d. Measure the moisture content of the stack gas</p> <p>e. Measure the particulate matter emission concentration</p> <p>f. Convert emissions concentration to lb/MMBtu emission rates</p>	<p>Method 1 in appendix A-1 to part 60 of this chapter.</p> <p>Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.</p> <p>Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005),^a or ANSI/ASME PTC 19.10-1981.^a</p> <p>Method 4 in appendix A-3 to part 60 of this chapter.</p> <p>Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A-3 and A-6 to part 60 of this chapter and a minimum 1 dscm of sample volume per run.</p> <p>Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.</p>
2. Mercury	<p>a. Select sampling ports location and the number of traverse points</p> <p>b. Determine velocity and volumetric flow-rate of the stack gas</p> <p>c. Determine oxygen and carbon dioxide concentrations of the stack gas</p> <p>d. Measure the moisture content of the stack gas</p> <p>e. Measure the mercury</p>	<p>Method 1 in appendix A-1 to part 60 of this chapter.</p> <p>Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.</p> <p>Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005),^a or ANSI/ASME PTC 19.10-1981.^a</p> <p>Method 4 in appendix A-3 to part 60 of this chapter.</p> <p>Method 29, 30A, or 30B in appendix A-8 to part 60 of this</p>

To conduct a performance test for the following pollutant . . .	You must. . .	Using . . .
	emission concentration	chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784-02. ^a Collect a minimum 2 dscm of sample volume with Method 29 of 101A per run. Use a minimum run time of 2 hours with Method 30A.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter .
3. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter .
	b. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter , or ASTM D6522-00 (Reapproved 2005), ^a or ANSI/ASME PTC 19.10-1981. ^a
	c. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter .
	d. Measure the carbon monoxide emission concentration	Method 10, 10A, or 10B in appendix A-4 to part 60 of this chapter or ASTM D6522-00 (Reapproved 2005) ^a and a minimum 1 hour sampling time per run.

^a Incorporated by reference, see [§ 63.14](#).

[Table 5 to Subpart JJJJJ of Part 63 - Fuel Analysis Requirements](#)

As stated in [§ 63.11213](#), you must comply with the following requirements for fuel analysis testing for affected sources:

To conduct a fuel analysis for the following pollutant . . .	You must. . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.11213(b) or ASTM D2234/D2234M ^a (for coal) or ASTM D6323 ^a (for biomass) or equivalent.
	b. Compose fuel samples	Procedure in § 63.11213(b) or equivalent.
	c. Prepare composited fuel	EPA SW-846-3050B ^a (for solid samples) or EPA SW-846-3020A ^a (for liquid samples) or ASTM D2013/D2013M ^a (for

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
	samples	coal) or ASTM D5198 ^a (for biomass) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 ^a (for coal) or ASTM E711 ^a (for biomass) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 ^a or ASTM E871 ^a or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 ^a (for coal) or EPA SW-846-7471B ^a (for solid samples) or EPA SW-846-7470A ^a (for liquid samples) or equivalent.
	g. Convert concentrations into units of lb/MMBtu of heat content	

^a Incorporated by reference, see [§ 63.14](#).

Table 6 to Subpart JJJJJ of Part 63 - Establishing Operating Limits

As stated in [§ 63.11211](#), you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM or mercury	a. Wet scrubber operating parameters	Establish site-specific minimum scrubber pressure drop and minimum scrubber liquid flow rate operating limits according to § 63.11211(b)	Data from the pressure drop and liquid flow rate monitors and the PM or mercury performance stack tests	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average pressure drop and liquid flow rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
	b. Electrostatic precipitator operating parameters	Establish a site-specific minimum total secondary electric power operating limit according to § 63.11211(b)	Data from the secondary electric power monitors and the PM or mercury performance stack tests	<p>(a) You must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests;</p> <p>(b) Determine the average total secondary electric power for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.</p>
2. Mercury	Dry sorbent or activated carbon injection rate operating parameters	Establish a site-specific minimum sorbent or activated carbon injection rate operating limit according to § 63.11211(b)	Data from the sorbent or activated carbon injection rate monitors and the mercury performance stack tests	<p>(a) You must collect sorbent or activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests;</p> <p>(b) Determine the average sorbent or activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.</p> <p>(c) When your unit operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction, as defined in § 63.11237, to determine the required injection rate.</p>
3. CO	Oxygen	Establish a unit-specific limit for minimum oxygen level	Data from the oxygen analyzer system specified	(a) You must collect oxygen data every 15 minutes during the entire period of the

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
			in § 63.11224(a)	<p>performance stack tests;</p> <p>(b) Determine the average hourly oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.</p>
4. Any pollutant for which compliance is demonstrated by a performance stack test	Boiler operating load	Establish a unit-specific limit for maximum operating load according to § 63.11212(c)	Data from the operating load monitors (fuel feed monitors or steam generation monitors)	<p>(a) You must collect operating load data (fuel feed rate or steam generation data) every 15 minutes during the entire period of the performance test.</p> <p>(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.</p> <p>(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.</p>

[[78 FR 7520](#), Feb. 1, 2013, as amended at [81 FR 63130](#), Sept. 14, 2016]

[Table 7 to Subpart JJJJJ of Part 63 - Demonstrating Continuous Compliance](#)

As stated in [§ 63.11222](#), you must show continuous compliance with the emission limitations for affected sources according to the following:

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.11224(e) and § 63.11221 ; and

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
	<ul style="list-style-type: none"> b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.11224(f) and operating the fabric filter such that the requirements in § 63.11222(a)(4) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow Rate	<ul style="list-style-type: none"> a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow rate at or above the minimum pressure drop and minimum liquid flow rate according to § 63.11211.
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate	<ul style="list-style-type: none"> a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to § 63.11211.
5. Electrostatic Precipitator Total Secondary Electric Power	<ul style="list-style-type: none"> a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum total secondary electric power according to § 63.11211.
6. Fuel Pollutant Content	<ul style="list-style-type: none"> a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.11213 as applicable; and b. Keeping monthly records of fuel use according to §§ 63.11222(a)(2) and 63.11225(b)(4).
7. Oxygen content	a. Continuously monitoring the oxygen content of flue gas according to § 63.11224 (This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7)); and

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
	<ul style="list-style-type: none"> b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average oxygen content at or above the minimum oxygen level established during the most recent CO performance test.
8. CO emissions	<ul style="list-style-type: none"> a. Continuously monitoring the CO concentration in the combustion exhaust according to §§ 63.11224 and 63.11221; and b. Correcting the data to 3 percent oxygen, and reducing the data to 1-hour averages; and c. Reducing the data from the hourly averages to 10-day rolling averages; and d. Maintaining the 10-day rolling average CO concentration at or below the applicable emission limit in Table 1 to this subpart.
9. Boiler operating load	<ul style="list-style-type: none"> a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to § 63.11212(c) and Table 6 to this subpart.

[78 FR 7521, Feb. 1, 2013]

Table 8 to Subpart JJJJJ of Part 63 - Applicability of General Provisions to Subpart JJJJJ

As stated in § 63.11235, you must comply with the applicable General Provisions according to the following:

General provisions cite	Subject	Does it apply?
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.11237.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	No

General provisions cite	Subject	Does it apply?
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.11205 for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(h)(2) to (9)	Determining compliance with opacity emission standards	Yes.
§ 63.7(a), (b), (c), (d), (e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.11210 .
§ 63.8(a), (b), (c)(1), (c)(1)(ii), (c)(2) to (c)(9), (d)(1) and (d)(2), (e),(f), and (g)	Monitoring Requirements	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes, excluding the information required in § 63.9(h)(2)(i)(B), (D), (E) and (F) . See § 63.11225 .
§ 63.10(a) and (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or	No.

General provisions cite	Subject	Does it apply?
	shutdowns	
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.11225 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Allows use of SSM plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	SSM reports	No. See § 63.11225 for malfunction reporting requirements.

General provisions cite	Subject	Does it apply?
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)	Reserved	No.

[[76 FR 15591](#), Mar. 21, 2011, as amended at [78 FR 7521](#), Feb. 1, 2013]

APPENDIX C

Subpart CCCCCC - National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

Source: [73 FR 1945](#), Jan. 10, 2008, unless otherwise noted.

What This Subpart Covers

§ 63.11110 What is the purpose of this subpart?

This subpart establishes national emission limitations and management practices for hazardous air pollutants (HAP) emitted from the loading of gasoline storage tanks at gasoline dispensing facilities (GDF). This subpart also establishes requirements to demonstrate compliance with the emission limitations and management practices.

§ 63.11111 Am I subject to the requirements in this subpart?

- (a) The affected source to which this subpart applies is each GDF that is located at an area source. The affected source includes each gasoline cargo tank during the delivery of product to a GDF and also includes each storage tank.
- (b) If your GDF has a monthly throughput of less than 10,000 gallons of gasoline, you must comply with the requirements in [§ 63.11116](#).
- (c) If your GDF has a monthly throughput of 10,000 gallons of gasoline or more, you must comply with the requirements in [§ 63.11117](#).
- (d) If your GDF has a monthly throughput of 100,000 gallons of gasoline or more, you must comply with the requirements in [§ 63.11118](#).
- (e) An affected source shall, upon request by the Administrator, demonstrate that their monthly throughput is less than the 10,000-gallon or the 100,000-gallon threshold level, as applicable. For new or reconstructed affected sources, as specified in [§ 63.11112\(b\)](#) and [\(c\)](#), recordkeeping to document monthly throughput must begin upon startup of the affected source. For existing sources, as specified in [§ 63.11112\(d\)](#), recordkeeping to document monthly throughput must begin on January 10, 2008. For existing sources that are subject to this subpart only because they load gasoline into fuel tanks other than those in motor vehicles, as defined in [§ 63.11132](#), recordkeeping to document monthly throughput must begin on January 24, 2011. Records required under this paragraph shall be kept for a period of 5 years.
- (f) If you are an owner or operator of affected sources, as defined in [paragraph \(a\)](#) of this section, you are not required to obtain a permit under [40 CFR part 70](#) or [40 CFR part 71](#) as a result of being subject to this subpart. However, you must still apply for and obtain a permit under [40 CFR part 70](#) or [40 CFR part 71](#) if you meet one or more of the applicability criteria found in [40 CFR 70.3\(a\)](#) and [\(b\)](#) or [40 CFR 71.3\(a\)](#) and [\(b\)](#).
- (g) The loading of aviation gasoline into storage tanks at airports, and the subsequent transfer of aviation gasoline within the airport, is not subject to this subpart.
- (h) Monthly throughput is the total volume of gasoline loaded into, or dispensed from, all the gasoline storage tanks located at a single affected GDF. If an area source has two or more GDF at separate locations within the area source, each GDF is treated as a separate affected source.
- (i) If your affected source's throughput ever exceeds an applicable throughput threshold, the affected source will remain subject to the requirements for sources above the threshold, even if the affected source throughput later falls below the applicable throughput threshold.

(j) The dispensing of gasoline from a fixed gasoline storage tank at a GDF into a portable gasoline tank for the on-site delivery and subsequent dispensing of the gasoline into the fuel tank of a motor vehicle or other gasoline-fueled engine or equipment used within the area source is only subject to [§ 63.11116 of this subpart](#).

(k) For any affected source subject to the provisions of this subpart and another Federal rule, you may elect to comply only with the more stringent provisions of the applicable subparts. You must consider all provisions of the rules, including monitoring, recordkeeping, and reporting. You must identify the affected source and provisions with which you will comply in your Notification of Compliance Status required under [§ 63.11124](#). You also must demonstrate in your Notification of Compliance Status that each provision with which you will comply is at least as stringent as the otherwise applicable requirements in this subpart. You are responsible for making accurate determinations concerning the more stringent provisions, and noncompliance with this rule is not excused if it is later determined that your determination was in error, and, as a result, you are violating this subpart. Compliance with this rule is your responsibility and the Notification of Compliance Status does not alter or affect that responsibility.

[[73 FR 1945](#), Jan. 10, 2008, as amended at [76 FR 4181](#), Jan. 24, 2011]

[§ 63.11112 What parts of my affected source does this subpart cover?](#)

(a) The emission sources to which this subpart applies are gasoline storage tanks and associated equipment components in vapor or liquid gasoline service at new, reconstructed, or existing GDF that meet the criteria specified in [§ 63.11111](#). Pressure/Vacuum vents on gasoline storage tanks and the equipment necessary to unload product from cargo tanks into the storage tanks at GDF are covered emission sources. The equipment used for the refueling of motor vehicles is not covered by this subpart.

(b) An affected source is a new affected source if you commenced construction on the affected source after November 9, 2006, and you meet the applicability criteria in [§ 63.11111](#) at the time you commenced operation.

(c) An affected source is reconstructed if you meet the criteria for reconstruction as defined in [§ 63.2](#).

(d) An affected source is an existing affected source if it is not new or reconstructed.

[§ 63.11113 When do I have to comply with this subpart?](#)

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to [paragraphs \(a\)\(1\) and \(2\)](#) of this section, except as specified in [paragraph \(d\)](#) of this section.

(1) If you start up your affected source before January 10, 2008, you must comply with the standards in this subpart no later than January 10, 2008.

(2) If you start up your affected source after January 10, 2008, you must comply with the standards in this subpart upon startup of your affected source.

(b) If you have an existing affected source, you must comply with the standards in this subpart no later than January 10, 2011.

(c) If you have an existing affected source that becomes subject to the control requirements in this subpart because of an increase in the monthly throughput, as specified in [§ 63.11111\(c\)](#) or [§ 63.11111\(d\)](#), you must comply with the standards in this subpart no later than 3 years after the affected source becomes subject to the control requirements in this subpart.

(d) If you have a new or reconstructed affected source and you are complying with Table 1 to this subpart, you must comply according to [paragraphs \(d\)\(1\)](#) and [\(2\)](#) of this section.

(1) If you start up your affected source from November 9, 2006 to September 23, 2008, you must comply no later than September 23, 2008.

(2) If you start up your affected source after September 23, 2008, you must comply upon startup of your affected source.

(e) The initial compliance demonstration test required under [§ 63.11120\(a\)\(1\)](#) and [\(2\)](#) must be conducted as specified in [paragraphs \(e\)\(1\)](#) and [\(2\)](#) of this section.

(1) If you have a new or reconstructed affected source, you must conduct the initial compliance test upon installation of the complete vapor balance system.

(2) If you have an existing affected source, you must conduct the initial compliance test as specified in [paragraphs \(e\)\(2\)\(i\)](#) or [\(e\)\(2\)\(ii\)](#) of this section.

(i) For vapor balance systems installed on or before December 15, 2009, you must test no later than 180 days after the applicable compliance date specified in [paragraphs \(b\)](#) or [\(c\)](#) of this section.

(ii) For vapor balance systems installed after December 15, 2009, you must test upon installation of the complete vapor balance system.

(f) If your GDF is subject to the control requirements in this subpart only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in [§ 63.11132](#), you must comply with the standards in this subpart as specified in [paragraphs \(f\)\(1\)](#) or [\(f\)\(2\)](#) of this section.

(1) If your GDF is an existing facility, you must comply by January 24, 2014.

(2) If your GDF is a new or reconstructed facility, you must comply by the dates specified in [paragraphs \(f\)\(2\)\(i\)](#) and [\(ii\)](#) of this section.

(i) If you start up your GDF after December 15, 2009, but before January 24, 2011, you must comply no later than January 24, 2011.

(ii) If you start up your GDF after January 24, 2011, you must comply upon startup of your GDF.

[[73 FR 1945](#), Jan. 10, 2008, as amended at [73 FR 35944](#), June 25, 2008; [76 FR 4181](#), Jan. 24, 2011]

Emission Limitations and Management Practices

§ 63.11115 What are my general duties to minimize emissions?

Each owner or operator of an affected source under this subpart must comply with the requirements of [paragraphs \(a\)](#) and [\(b\)](#) of this section.

(a) You must, at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) You must keep applicable records and submit reports as specified in [§ 63.11125\(d\)](#) and [§ 63.11126\(b\)](#).

[[76 FR 4182](#), Jan. 24, 2011]

[§ 63.11116 Requirements for facilities with monthly throughput of less than 10,000 gallons of gasoline.](#)

(a) You must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use;

(4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

(b) You are not required to submit notifications or reports as specified in [§ 63.11125](#), [§ 63.11126](#), or [subpart A of this part](#), but you must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

(c) You must comply with the requirements of this subpart by the applicable dates specified in [§ 63.11113](#).

(d) Portable gasoline containers that meet the requirements of [40 CFR part 59, subpart F](#), are considered acceptable for compliance with [paragraph \(a\)\(3\)](#) of this section.

[[73 FR 1945](#), Jan. 10, 2008, as amended at [76 FR 4182](#), Jan. 24, 2011]

[§ 63.11117 Requirements for facilities with monthly throughput of 10,000 gallons of gasoline or more.](#)

(a) You must comply with the requirements in section [§ 63.11116\(a\)](#).

(b) Except as specified in [paragraph \(c\)](#) of this section, you must only load gasoline into storage tanks at your facility by utilizing submerged filling, as defined in [§ 63.11132](#), and as specified in [paragraphs \(b\)\(1\), \(b\)\(2\), or \(b\)\(3\)](#) of this section. The applicable distances in paragraphs (b)(1) and (2) shall be measured from the point in the opening of the submerged fill pipe that is the greatest distance from the bottom of the storage tank.

(1) Submerged fill pipes installed on or before November 9, 2006, must be no more than 12 inches from the bottom of the tank.

(2) Submerged fill pipes installed after November 9, 2006, must be no more than 6 inches from the bottom of the tank.

(3) Submerged fill pipes not meeting the specifications of [paragraphs \(b\)\(1\) or \(b\)\(2\)](#) of this section are allowed if the owner or operator can demonstrate that the liquid level in the tank is always above the entire opening of the fill pipe. Documentation providing such demonstration must be made available for inspection by the Administrator's delegated representative during the course of a site visit.

(c) Gasoline storage tanks with a capacity of less than 250 gallons are not required to comply with the submerged fill requirements in [paragraph \(b\)](#) of this section, but must comply only with all of the requirements in [§ 63.11116](#).

(d) You must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

(e) You must submit the applicable notifications as required under [§ 63.11124\(a\)](#).

(f) You must comply with the requirements of this subpart by the applicable dates contained in [§ 63.11113](#).

[[73 FR 1945](#), Jan. 10, 2008, as amended at [73 FR 12276](#), Mar. 7, 2008; [76 FR 4182](#), Jan. 24, 2011]

[§ 63.11118 Requirements for facilities with monthly throughput of 100,000 gallons of gasoline or more.](#)

(a) You must comply with the requirements in [§§ 63.11116\(a\)](#) and [63.11117\(b\)](#).

(b) Except as provided in [paragraph \(c\)](#) of this section, you must meet the requirements in either paragraph (b)(1) or [paragraph \(b\)\(2\)](#) of this section.

(1) Each management practice in Table 1 to this subpart that applies to your GDF.

(2) If, prior to January 10, 2008, you satisfy the requirements in both [paragraphs \(b\)\(2\)\(i\)](#) and [\(ii\)](#) of this section, you will be deemed in compliance with this subsection.

(i) You operate a vapor balance system at your GDF that meets the requirements of either paragraph (b)(2)(i)(A) or [paragraph \(b\)\(2\)\(i\)\(B\)](#) of this section.

(A) Achieves emissions reduction of at least 90 percent.

(B) Operates using management practices at least as stringent as those in Table 1 to this subpart.

(ii) Your gasoline dispensing facility is in compliance with an enforceable State, local, or tribal rule or permit that contains requirements of either paragraph (b)(2)(i)(A) or [paragraph \(b\)\(2\)\(i\)\(B\)](#) of this section.

(c) The emission sources listed in [paragraphs \(c\)\(1\)](#) through [\(3\)](#) of this section are not required to comply with the control requirements in [paragraph \(b\)](#) of this section, but must comply with the requirements in [§ 63.11117](#).

(1) Gasoline storage tanks with a capacity of less than 250 gallons that are constructed after January 10, 2008.

(2) Gasoline storage tanks with a capacity of less than 2,000 gallons that were constructed before January 10, 2008.

(3) Gasoline storage tanks equipped with floating roofs, or the equivalent.

(d) Cargo tanks unloading at GDF must comply with the management practices in Table 2 to this subpart.

(e) You must comply with the applicable testing requirements contained in [§ 63.11120](#).

(f) You must submit the applicable notifications as required under [§ 63.11124](#).

(g) You must keep records and submit reports as specified in [§§ 63.11125](#) and [63.11126](#).

(h) You must comply with the requirements of this subpart by the applicable dates contained in [§ 63.11113](#).

[[73 FR 1945](#), Jan. 10, 2008, as amended at [73 FR 12276](#), Mar. 7, 2008]

[Testing and Monitoring Requirements](#)

§ 63.11120 What testing and monitoring requirements must I meet?

(a) Each owner or operator, at the time of installation, as specified in [§ 63.11113\(e\)](#), of a vapor balance system required under [§ 63.11118\(b\)\(1\)](#), and every 3 years thereafter, must comply with the requirements in [paragraphs \(a\)\(1\) and \(2\)](#) of this section.

(1) You must demonstrate compliance with the leak rate and cracking pressure requirements, specified in item 1(g) of Table 1 to this subpart, for pressure-vacuum vent valves installed on your gasoline storage tanks using the test methods identified in [paragraph \(a\)\(1\)\(i\)](#) or [paragraph \(a\)\(1\)\(ii\)](#) of this section.

(i) California Air Resources Board Vapor Recovery Test Procedure TP-201.1E, - Leak Rate and Cracking Pressure of Pressure/Vacuum Vent Valves, adopted October 8, 2003 (incorporated by reference, see [§ 63.14](#)).

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in [§ 63.7\(f\)](#).

(2) You must demonstrate compliance with the static pressure performance requirement specified in item 1(h) of Table 1 to this subpart for your vapor balance system by conducting a static pressure test on your gasoline storage tanks using the test methods identified in [paragraphs \(a\)\(2\)\(i\), \(a\)\(2\)\(ii\), or \(a\)\(2\)\(iii\)](#) of this section.

(i) California Air Resources Board Vapor Recovery Test Procedure TP-201.3, - Determination of 2-Inch WC Static Pressure Performance of Vapor Recovery Systems of Dispensing Facilities, adopted April 12, 1996, and amended March 17, 1999 (incorporated by reference, see [§ 63.14](#)).

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in [§ 63.7\(f\)](#).

(iii) Bay Area Air Quality Management District Source Test Procedure ST-30 - Static Pressure Integrity Test - Underground Storage Tanks, adopted November 30, 1983, and amended December 21, 1994 (incorporated by reference, see [§ 63.14](#)).

(b) Each owner or operator choosing, under the provisions of [§ 63.6\(g\)](#), to use a vapor balance system other than that described in Table 1 to this subpart must demonstrate to the Administrator or delegated authority under [paragraph § 63.11131\(a\) of this subpart](#), the equivalency of their vapor balance system to that described in Table 1 to this subpart using the procedures specified in [paragraphs \(b\)\(1\) through \(3\)](#) of this section.

(1) You must demonstrate initial compliance by conducting an initial performance test on the vapor balance system to demonstrate that the vapor balance system achieves 95 percent reduction using the California Air Resources Board Vapor Recovery Test Procedure TP-201.1, - Volumetric Efficiency for Phase I Vapor Recovery Systems, adopted April 12, 1996, and amended February 1, 2001, and October 8, 2003, (incorporated by reference, see [§ 63.14](#)).

(2) You must, during the initial performance test required under [paragraph \(b\)\(1\)](#) of this section, determine and document alternative acceptable values for the leak rate and cracking pressure requirements specified in item 1(g) of Table 1 to this subpart and for the static pressure performance requirement in item 1(h) of Table 1 to this subpart.

(3) You must comply with the testing requirements specified in [paragraph \(a\)](#) of this section.

(c) Conduct of performance tests. Performance tests conducted for this subpart shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance (*i.e.*, performance based on normal operating conditions) of the affected source. Upon request, the owner or operator shall

make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(d) Owners and operators of gasoline cargo tanks subject to the provisions of Table 2 to this subpart must conduct annual certification testing according to the vapor tightness testing requirements found in [§ 63.11092\(f\)](#).

[[73 FR 1945](#), Jan. 10, 2008, as amended at [76 FR 4182](#), Jan. 24, 2011]

Notifications, Records, and Reports

§ 63.11124 What notifications must I submit and when?

(a) Each owner or operator subject to the control requirements in [§ 63.11117](#) must comply with [paragraphs \(a\)\(1\) through \(3\)](#) of this section.

(1) You must submit an Initial Notification that you are subject to this subpart by May 9, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later, or at the time you become subject to the control requirements in [§ 63.11117](#), unless you meet the requirements in [paragraph \(a\)\(3\)](#) of this section. If your affected source is subject to the control requirements in [§ 63.11117](#) only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in [§ 63.11132](#), you must submit the Initial Notification by May 24, 2011, or no later than 120 days after the source becomes subject to this subpart, whichever is later. The Initial Notification must contain the information specified in [paragraphs \(a\)\(1\)\(i\) through \(iii\)](#) of this section. The notification must be submitted to the applicable EPA Regional office and delegated state authority as specified in [§ 63.13](#).

(i) The name and address of the owner and the operator.

(ii) The address (i.e., physical location) of the GDF.

(iii) A statement that the notification is being submitted in response to this subpart and identifying the requirements in paragraphs (a) through (c) of [§ 63.11117](#) that apply to you.

(2) You must submit a Notification of Compliance Status to the applicable EPA Regional Office and the delegated State authority, as specified in [§ 63.13](#), within 60 days of the applicable compliance date specified in [§ 63.11113](#), unless you meet the requirements in [paragraph \(a\)\(3\)](#) of this section. The Notification of Compliance Status must be signed by a responsible official who must certify its accuracy, must indicate whether the source has complied with the requirements of this subpart, and must indicate whether the facilities' monthly throughput is calculated based on the volume of gasoline loaded into all storage tanks or on the volume of gasoline dispensed from all storage tanks. If your facility is in compliance with the requirements of this subpart at the time the Initial Notification required under [paragraph \(a\)\(1\)](#) of this section is due, the Notification of Compliance Status may be submitted in lieu of the Initial Notification provided it contains the information required under [paragraph \(a\)\(1\)](#) of this section.

(3) If, prior to January 10, 2008, you are operating in compliance with an enforceable State, local, or tribal rule or permit that requires submerged fill as specified in [§ 63.11117\(b\)](#), you are not required to submit an Initial Notification or a Notification of Compliance Status under [paragraph \(a\)\(1\)](#) or [paragraph \(a\)\(2\)](#) of this section.

(b) Each owner or operator subject to the control requirements in [§ 63.11118](#) must comply with [paragraphs \(b\)\(1\) through \(5\)](#) of this section.

(1) You must submit an Initial Notification that you are subject to this subpart by May 9, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later, or at the time you become subject to the control requirements in [§ 63.11118](#). If your affected source is subject to the control requirements in [§ 63.11118](#) only

because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in [§ 63.11132](#), you must submit the Initial Notification by May 24, 2011, or no later than 120 days after the source becomes subject to this subpart, whichever is later. The Initial Notification must contain the information specified in [paragraphs \(b\)\(1\)\(i\) through \(iii\)](#) of this section. The notification must be submitted to the applicable EPA Regional office and delegated state authority as specified in [§ 63.13](#).

(i) The name and address of the owner and the operator.

(ii) The address (i.e., physical location) of the GDF.

(iii) A statement that the notification is being submitted in response to this subpart and identifying the requirements in paragraphs (a) through (c) of [§ 63.11118](#) that apply to you.

(2) You must submit a Notification of Compliance Status to the applicable EPA Regional Office and the delegated State authority, as specified in [§ 63.13](#), in accordance with the schedule specified in [§ 63.9\(h\)](#). The Notification of Compliance Status must be signed by a responsible official who must certify its accuracy, must indicate whether the source has complied with the requirements of this subpart, and must indicate whether the facility's throughput is determined based on the volume of gasoline loaded into all storage tanks or on the volume of gasoline dispensed from all storage tanks. If your facility is in compliance with the requirements of this subpart at the time the Initial Notification required under [paragraph \(b\)\(1\)](#) of this section is due, the Notification of Compliance Status may be submitted in lieu of the Initial Notification provided it contains the information required under [paragraph \(b\)\(1\)](#) of this section.

(3) If, prior to January 10, 2008, you satisfy the requirements in both [paragraphs \(b\)\(3\)\(i\)](#) and [\(ii\)](#) of this section, you are not required to submit an Initial Notification or a Notification of Compliance Status under [paragraph \(b\)\(1\)](#) or [paragraph \(b\)\(2\)](#) of this subsection.

(i) You operate a vapor balance system at your gasoline dispensing facility that meets the requirements of either [paragraphs \(b\)\(3\)\(i\)\(A\)](#) or [\(b\)\(3\)\(i\)\(B\)](#) of this section.

(A) Achieves emissions reduction of at least 90 percent.

(B) Operates using management practices at least as stringent as those in Table 1 to this subpart.

(ii) Your gasoline dispensing facility is in compliance with an enforceable State, local, or tribal rule or permit that contains requirements of either [paragraphs \(b\)\(3\)\(i\)\(A\)](#) or [\(b\)\(3\)\(i\)\(B\)](#) of this section.

(4) You must submit a Notification of Performance Test, as specified in [§ 63.9\(e\)](#), prior to initiating testing required by [§ 63.11120\(a\)](#) and [\(b\)](#).

(5) You must submit additional notifications specified in [§ 63.9](#), as applicable.

[[73 FR 1945](#), Jan. 10, 2008, as amended at [73 FR 12276](#), Mar. 7, 2008; [76 FR 4182](#), Jan. 24, 2011; [85 FR 73919](#), Nov. 19, 2020]

[§ 63.11125 What are my recordkeeping requirements?](#)

(a) Each owner or operator subject to the management practices in [§ 63.11118](#) must keep records of all tests performed under [§ 63.11120\(a\)](#) and [\(b\)](#).

(b) Records required under [paragraph \(a\)](#) of this section shall be kept for a period of 5 years and shall be made available for inspection by the Administrator's delegated representatives during the course of a site visit.

(c) Each owner or operator of a gasoline cargo tank subject to the management practices in Table 2 to this subpart must keep records documenting vapor tightness testing for a period of 5 years. Documentation must include each of the items specified in [§ 63.11094\(b\)\(2\)\(i\)](#) through [\(viii\)](#). Records of vapor tightness testing must be retained as specified in either paragraph (c)(1) or [paragraph \(c\)\(2\)](#) of this section.

(1) The owner or operator must keep all vapor tightness testing records with the cargo tank.

(2) As an alternative to keeping all records with the cargo tank, the owner or operator may comply with the requirements of [paragraphs \(c\)\(2\)\(i\)](#) and [\(ii\)](#) of this section.

(i) The owner or operator may keep records of only the most recent vapor tightness test with the cargo tank, and keep records for the previous 4 years at their office or another central location.

(ii) Vapor tightness testing records that are kept at a location other than with the cargo tank must be instantly available (*e.g.*, via e-mail or facsimile) to the Administrator's delegated representative during the course of a site visit or within a mutually agreeable time frame. Such records must be an exact duplicate image of the original paper copy record with certifying signatures.

(d) Each owner or operator of an affected source under this subpart shall keep records as specified in [paragraphs \(d\)\(1\)](#) and [\(2\)](#) of this section.

(1) Records of the occurrence and duration of each malfunction of operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(2) Records of actions taken during periods of malfunction to minimize emissions in accordance with [§ 63.11115\(a\)](#), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[[73 FR 1945](#), Jan. 10, 2008, as amended at [76 FR 4183](#), Jan. 24, 2011]

[§ 63.11126 What are my reporting requirements?](#)

(a) Each owner or operator subject to the management practices in [§ 63.11118](#) shall report to the Administrator the results of all volumetric efficiency tests required under [§ 63.11120\(b\)](#). Reports submitted under this paragraph must be submitted within 180 days of the completion of the performance testing.

(b) Each owner or operator of an affected source under this subpart shall report, by March 15 of each year, the number, duration, and a brief description of each type of malfunction which occurred during the previous calendar year and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with [§ 63.11115\(a\)](#), including actions taken to correct a malfunction. No report is necessary for a calendar year in which no malfunctions occurred.

[[76 FR 4183](#), Jan. 24, 2011]

[Other Requirements and Information](#)

[§ 63.11130 What parts of the General Provisions apply to me?](#)

Table 3 to this subpart shows which parts of the General Provisions apply to you.

[§ 63.11131 Who implements and enforces this subpart?](#)

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as the applicable State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under [subpart E of this part](#), the authorities contained in [paragraph \(c\)](#) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are as specified in [paragraphs \(c\)\(1\) through \(3\)](#) of this section.

(1) Approval of alternatives to the requirements in [§§ 63.11116 through 63.11118](#) and [63.11120](#).

(2) Approval of major alternatives to test methods under [§ 63.7\(e\)\(2\)\(ii\)](#) and [\(f\)](#), as defined in [§ 63.90](#), and as required in this subpart.

(3) Approval of major alternatives to recordkeeping and reporting under [§ 63.10\(f\)](#), as defined in [§ 63.90](#), and as required in this subpart.

[§ 63.11132 What definitions apply to this subpart?](#)

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA), or in subparts A and BBBBBB of this part. For purposes of this subpart, definitions in this section supersede definitions in other parts or subparts.

Dual-point vapor balance system means a type of vapor balance system in which the storage tank is equipped with an entry port for a gasoline fill pipe and a separate exit port for a vapor connection.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater, which is used as a fuel for internal combustion engines.

Gasoline cargo tank means a delivery tank truck or railcar which is loading or unloading gasoline, or which has loaded or unloaded gasoline on the immediately previous load.

Gasoline dispensing facility (GDF) means any stationary facility which dispenses gasoline into the fuel tank of a motor vehicle, motor vehicle engine, nonroad vehicle, or nonroad engine, including a nonroad vehicle or nonroad engine used solely for competition. These facilities include, but are not limited to, facilities that dispense gasoline into on- and off-road, street, or highway motor vehicles, lawn equipment, boats, test engines, landscaping equipment, generators, pumps, and other gasoline-fueled engines and equipment.

Monthly throughput means the total volume of gasoline that is loaded into, or dispensed from, all gasoline storage tanks at each GDF during a month. Monthly throughput is calculated by summing the volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at each GDF during the current day, plus the total volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at each GDF during the previous 364 days, and then dividing that sum by 12.

Motor vehicle means any self-propelled vehicle designed for transporting persons or property on a street or highway.

Nonroad engine means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 7411 of this title or section 7521 of this title.

Nonroad vehicle means a vehicle that is powered by a nonroad engine, and that is not a motor vehicle or a vehicle used solely for competition.

Submerged filling means, for the purposes of this subpart, the filling of a gasoline storage tank through a submerged fill pipe whose discharge is no more than the applicable distance specified in [§ 63.11117\(b\)](#) from the bottom of the tank. Bottom filling of gasoline storage tanks is included in this definition.

Vapor balance system means a combination of pipes and hoses that create a closed system between the vapor spaces of an unloading gasoline cargo tank and a receiving storage tank such that vapors displaced from the storage tank are transferred to the gasoline cargo tank being unloaded.

Vapor-tight means equipment that allows no loss of vapors. Compliance with vapor-tight requirements can be determined by checking to ensure that the concentration at a potential leak source is not equal to or greater than 100 percent of the Lower Explosive Limit when measured with a combustible gas detector, calibrated with propane, at a distance of 1 inch from the source.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in [§ 63.11092\(f\) of this part](#).

[[73 FR 1945](#), Jan. 10, 2008, as amended at [76 FR 4183](#), Jan. 24, 2011]

Table 1 to Subpart CCCCCC of Part 63 - Applicability Criteria and Management Practices for Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More¹

If you own or operate	Then you must
1. A new, reconstructed, or existing GDF subject to § 63.11118	Install and operate a vapor balance system on your gasoline storage tanks that meets the design criteria in paragraphs (a) through (h). (a) All vapor connections and lines on the storage tank shall be equipped with closures that seal upon disconnect. (b) The vapor line from the gasoline storage tank to the gasoline cargo tank shall be vapor-tight, as defined in § 63.11132 . (c) The vapor balance system shall be designed such that the pressure in the tank truck does not exceed 18 inches water pressure or 5.9 inches water vacuum during product transfer. (d) The vapor recovery and product adaptors, and the method of connection with the delivery elbow, shall be designed so as to prevent the over-tightening or loosening of fittings during normal delivery operations. (e) If a gauge well separate from the fill tube is used, it shall be provided with a submerged drop tube that extends the same distance from the bottom of the storage tank as specified in § 63.11117(b) .

If you own or operate	Then you must
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- (f) Liquid fill connections for all systems shall be equipped with vapor-tight caps.
- (g) Pressure/vacuum (PV) vent valves shall be installed on the storage tank vent pipes. The pressure specifications for PV vent valves shall be: a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water. The total leak rate of all PV vent valves at an affected facility, including connections, shall not exceed 0.17 cubic foot per hour at a pressure of 2.0 inches of water and 0.63 cubic foot per hour at a vacuum of 4 inches of water.
- (h) The vapor balance system shall be capable of meeting the static pressure performance requirement of the following equation:

$$Pf = 2e^{-500.887/v}$$

Where:

Pf = Minimum allowable final pressure, inches of water.

v = Total ullage affected by the test, gallons.

e = Dimensionless constant equal to approximately 2.718.

2 = The initial pressure, inches water.

<p>2. A new or reconstructed GDF, or any storage tank(s) constructed after November 9, 2006, at an existing affected facility subject to § 63.11118</p>	<p>Equip your gasoline storage tanks with a dual-point vapor balance system, as defined in § 63.11132, and comply with the requirements of item 1 in this Table.</p>
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¹ The management practices specified in this Table are not applicable if you are complying with the requirements in [§ 63.11118\(b\)\(2\)](#), except that if you are complying with the requirements in [§ 63.11118\(b\)\(2\)\(i\)\(B\)](#), you must operate using management practices at least as stringent as those listed in this Table.

[[73 FR 1945](#), Jan. 10, 2008, as amended at [73 FR 35944](#), June 25, 2008; [76 FR 4184](#), Jan. 24, 2011]

[Table 2 to Subpart CCCCCC of Part 63 - Applicability Criteria and Management Practices for Gasoline Cargo Tanks Unloading at Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More](#)

If you own or operate	Then you must
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A gasoline	Not unload gasoline into a storage tank at a GDF subject to the control requirements in this subpart
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If you own or operate	Then you must
cargo tank	<p>unless the following conditions are met:</p> <ul style="list-style-type: none"> (i) All hoses in the vapor balance system are properly connected, (ii) The adapters or couplers that attach to the vapor line on the storage tank have closures that seal upon disconnect, (iii) All vapor return hoses, couplers, and adapters used in the gasoline delivery are vapor-tight, (iv) All tank truck vapor return equipment is compatible in size and forms a vapor-tight connection with the vapor balance equipment on the GDF storage tank, and (v) All hatches on the tank truck are closed and securely fastened. (vi) The filling of storage tanks at GDF shall be limited to unloading from vapor-tight gasoline cargo tanks. Documentation that the cargo tank has met the specifications of EPA Method 27 shall be carried with the cargo tank, as specified in § 63.11125(c).

[[73 FR 1945](#), Jan. 10, 2008, as amended at [76 FR 4184](#), Jan. 24, 2011]

Table 3 to Subpart CCCCCC of Part 63 - Applicability of General Provisions

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.1	Applicability	Initial applicability determination; applicability after standard established; permit requirements; extensions, notifications	Yes, specific requirements given in § 63.11111 .
§ 63.1(c)(2)	Title V Permit	Requirements for obtaining a title V permit from the applicable permitting authority	Yes, § 63.11111(f) of subpart CCCCCC exempts identified area sources from the obligation to obtain title V operating permits.
§ 63.2	Definitions	Definitions for part 63 standards	Yes, additional definitions in § 63.11132 .
§ 63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§ 63.4	Prohibited Activities and	Prohibited activities; Circumvention,	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCC
	Circumvention	severability	
§ 63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes, except that these notifications are not required for facilities subject to § 63.11116
§ 63.6(a)	Compliance with Standards/Operation & Maintenance - Applicability	General Provisions apply unless compliance extension; General Provisions apply to area sources that become major	Yes.
§ 63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed Sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for CAA section 112(f)	Yes.
§ 63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	No.
§ 63.6(c)(1)-(2)	Compliance Dates for Existing Sources	Comply according to date in this subpart, which must be no later than 3 years after effective date; for CAA section 112(f) standards, comply within 90 days of effective date unless compliance extension	No, § 63.11113 specifies the compliance dates.
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources That become major must comply with major source standards by date indicated in this subpart or by equivalent time period (e.g., 3 years)	No.
§ 63.6(d)	[Reserved]		
63.6(e)(1)(i)	General duty to minimize emissions	Operate to minimize emissions at all times; information Administrator will use to	No. See § 63.11115 for general duty

Citation	Subject	Brief description	Applies to subpart CCCCC
		determine if operation and maintenance requirements were met.	requirement.
63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	Owner or operator must correct malfunctions as soon as possible.	No.
§ 63.6(e)(2)	[Reserved]		
§ 63.6(e)(3)	Startup, Shutdown, and Malfunction (SSM) Plan	Requirement for SSM plan; content of SSM plan; actions during SSM	No.
§ 63.6(f)(1)	Compliance Except During SSM	You must comply with emission standards at all times except during SSM	No.
§ 63.6(f)(2)-(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§ 63.6(g)(1)-(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§ 63.6(h)(1)	Compliance with Opacity/Visible Emission (VE) Standards	You must comply with opacity/VE standards at all times except during SSM	No.
§ 63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards	If standard does not State test method, use EPA Method 9 for opacity in appendix A of part 60 of this chapter and EPA Method 22 for VE in appendix A of part 60 of this chapter	No.
§ 63.6(h)(2)(ii)	[Reserved]		
§ 63.6(h)(2)(iii)	Using Previous Tests To Demonstrate Compliance With Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart	No.
§ 63.6(h)(3)	[Reserved]		
§ 63.6(h)(4)	Notification of Opacity/VE Observation Date	Must notify Administrator of anticipated date of observation	No.
§ 63.6(h)(5)(i), (iii)-(v)	Conducting Opacity/VE Observations	Dates and schedule for conducting opacity/VE observations	No.
§ 63.6(h)(5)(ii)	Opacity Test Duration and	Must have at least 3 hours of observation	No.

Citation	Subject	Brief description	Applies to subpart CCCCCC
	Averaging Times	with 30 6-minute averages	
§ 63.6(h)(6)	Records of Conditions During Opacity/VE Observations	Must keep records available and allow Administrator to inspect	No.
§ 63.6(h)(7)(i)	Report Continuous Opacity Monitoring System (COMS) Monitoring Data From Performance Test	Must submit COMS data with other performance test data	No.
§ 63.6(h)(7)(ii)	Using COMS Instead of EPA Method 9	Can submit COMS data instead of EPA Method 9 results even if rule requires EPA Method 9 in appendix A of part 60 of this chapter , but must notify Administrator before performance test	No.
§ 63.6(h)(7)(iii)	Averaging Time for COMS During Performance Test	To determine compliance, must reduce COMS data to 6-minute averages	No.
§ 63.6(h)(7)(iv)	COMS Requirements	Owner/operator must demonstrate that COMS performance evaluations are conducted according to § 63.8(e) ; COMS are properly maintained and operated according to § 63.8(c) and data quality as § 63.8(d)	No.
§ 63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards	COMS is probable but not conclusive evidence of compliance with opacity standard, even if EPA Method 9 observation shows otherwise. Requirements for COMS to be probable evidence-proper maintenance, meeting Performance Specification 1 in appendix B of part 60 of this chapter , and data have not been altered	No.
§ 63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Administrator will use all COMS, EPA Method 9 (in appendix A of part 60 of this chapter), and EPA Method 22 (in appendix A of part 60 of this chapter) results, as well as information about operation and maintenance to determine compliance	No.
§ 63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard	No.
§ 63.6(i)(1)-(14)	Compliance Extension	Procedures and criteria for Administrator to	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
		grant compliance extension	
§ 63.6(j)	Presidential Compliance Exemption	President may exempt any source from requirement to comply with this subpart	Yes.
§ 63.7(a)(2)	Performance Test Dates	Dates for conducting initial performance testing; must conduct 180 days after compliance date	Yes.
§ 63.7(a)(3)	CAA Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time	Yes.
§ 63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§ 63.7(b)(2)	Notification of Re-scheduling	If have to reschedule performance test, must notify Administrator of rescheduled date as soon as practicable and without delay	Yes.
§ 63.7(c)	Quality Assurance (QA)/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with; test plan approval procedures; performance audit requirements; internal and external QA procedures for testing	Yes.
§ 63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
63.7(e)(1)	Conditions for Conducting Performance Tests	Performance test must be conducted under representative conditions	No, § 63.11120(c) specifies conditions for conducting performance tests.
§ 63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to this subpart and EPA test methods unless Administrator approves alternative	Yes.
§ 63.7(e)(3)	Test Run Duration	Must have three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used	Yes.
§ 63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an intermediate or major change, or alternative to a test method	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; must submit performance test data 60 days after end of test with the Notification of Compliance Status; keep data for 5 years	Yes.
§ 63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§ 63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§ 63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply	Yes.
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring of Flares	Monitoring requirements for flares in § 63.11 apply	Yes.
§ 63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§ 63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems; must install on each affected source or after combined with another affected source before it is released to the atmosphere provided the monitoring is sufficient to demonstrate compliance with the standard; if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	No.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	No.
§ 63.8(c)(1)(i)-(iii)	Operation and Maintenance of Continuous Monitoring Systems (CMS)	Must maintain and operate each CMS as specified in § 63.6(e)(1) ; must keep parts for routine repairs readily available; must develop a written SSM plan for CMS, as specified in § 63.6(e)(3)	No.
§ 63.8(c)(2)-(8)	CMS Requirements	Must install to get representative emission or	No.

Citation	Subject	Brief description	Applies to subpart CCCCCC
		parameter measurements; must verify operational status before or at performance test	
§ 63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc.; must keep quality control plan on record for 5 years; keep old versions for 5 years after revisions	No.
§ 63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	No.
§ 63.8(f)(1)-(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	No.
§ 63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system (CEMS)	No.
§ 63.8(g)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points; CEMS 1 hour averages computed over at least 4 equally spaced data points; data that cannot be used in average	No.
§ 63.9(a)	Notification Requirements	Applicability and State delegation	Yes.
§ 63.9(b)(1)-(2), (4)-(5)	Initial Notifications	Submit notification within 120 days after effective date, or no later than 120 days after the source becomes subject to this subpart, whichever is later; notification of intent to construct/reconstruct, notification of commencement of construction/reconstruction, notification of startup; contents of each	Yes.
§ 63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed best available control technology or lowest achievable emission rate	Yes.
§ 63.9(d)	Notification of Special Compliance Requirements for New Sources	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§ 63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§ 63.9(g)	Additional Notifications when Using CMS	Notification of performance evaluation; notification about use of COMS data; notification that exceeded criterion for relative accuracy alternative	Yes, however, there are no opacity standards.
§ 63.9(h)(1)-(6)	Notification of Compliance Status	Contents due 60 days after end of performance test or other compliance demonstration, except for opacity/VE, which are due 30 days after; when to submit to Federal vs. State authority	Yes, however, there are no opacity standards.
§ 63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change when notifications must be submitted	Yes.
§ 63.9(j)	Change in Previous Information	Must submit within 15 days after the change	Yes.
§ 63.9(k)	Notifications	Electronic reporting procedures	Yes, only as specified in § 63.9(j) .
§ 63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; when to submit to Federal vs. State authority; procedures for owners of more than one source	Yes.
§ 63.10(b)(1)	Recordkeeping/Reporting	General requirements; keep all records readily available; keep for 5 years	Yes.
§ 63.10(b)(2)(i)	Records related to SSM	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§ 63.10(b)(2)(ii)	Records related to SSM	Recordkeeping of malfunctions	No. <i>See</i> § 63.11125(d) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.

Citation	Subject	Brief description	Applies to subpart CCCCC
§ 63.10(b)(2)(iii)	Maintenance records	Recordkeeping of maintenance on air pollution control and monitoring equipment	Yes.
§ 63.10(b)(2)(iv)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(v)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)-(xi)	CMS Records	Malfunctions, inoperative, out-of-control periods	No.
§ 63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§ 63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	Yes.
§ 63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status	Yes.
§ 63.10(b)(3)	Records	Applicability determinations	Yes.
§ 63.10(c)	Records	Additional records for CMS	No.
§ 63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§ 63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§ 63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	No.
§ 63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§ 63.10(d)(5)	SSM Reports	Contents and submission	No. See § 63.11126(b) for malfunction reporting requirements.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.10(e)(1)-(2)	Additional CMS Reports	Must report results for each CEMS on a unit; written copy of CMS performance evaluation; two-three copies of COMS performance evaluation	No.
§ 63.10(e)(3)(i)-(iii)	Reports	Schedule for reporting excess emissions	No.
§ 63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§ 63.8(c)(7)-(8) and 63.10(c)(5)-(13)	No.
§ 63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§ 63.8(c)(7)-(8) and 63.10(c)(5)-(13)	No, § 63.11130(K) specifies excess emission events for this subpart.
§ 63.10(e)(3)(vi)-(viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for CMS; requires all of the information in §§ 63.10(c)(5)-(13) and 63.8(c)(7)-(8)	No.
§ 63.10(e)(4)	Reporting COMS Data	Must submit COMS data with performance test data	No.
§ 63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.11(b)	Flares	Requirements for flares	No.
§ 63.12	Delegation	State authority to enforce standards	Yes.
§ 63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§ 63.14	Incorporations by Reference	Test methods incorporated by reference	Yes.
§ 63.15	Availability of Information	Public and confidential information	Yes.

[[73 FR 1945](#), Jan. 10, 2008, as amended at [76 FR 4184](#), Jan. 24, 2011; [85 FR 73919](#), Nov. 19, 2020]