

ADEQ

ARKANSAS
Department of Environmental Quality

DEC 17 2014

Benny Bishop, Construction Manager
Peco Foods, Inc.
P. O. Box 1760
Tuscaloosa, AL 35403

Dear Mr. Bishop:

The enclosed Permit No. 2332-AOP-R0 is your authority to construct, operate, and maintain the equipment and/or control apparatus as set forth in your application initially received on 6/4/2014.

After considering the facts and requirements of A.C.A. §8-4-101 et seq. as referenced by §8-4-304, and implementing regulations, I have determined that Permit No. 2332-AOP-R0 for the construction and operation of equipment at Peco Foods, Inc. to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8, within thirty (30) days after service of this decision.

The applicant or permittee and any other person submitting public comments on the record may request an adjudicatory hearing and Commission review of the final permitting decisions as provided under Chapter Six of Regulation No. 8, Administrative Procedures, Arkansas Pollution Control and Ecology Commission. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,



Mike Bates
Chief, Air Division

Enclosure: Final Permit

RESPONSE TO COMMENTS

**PECO FOODS, INC.
PERMIT #2332-AOP-R0
AFIN: 61-01017**

On October 5, and October 16, 2014, the Director of the Arkansas Department of Environmental Quality gave notice of a draft permitting decision for the above referenced facility. During the comment period, written comments on the draft permitting decision were submitted on behalf of the facility and the public. The Department's response to these issues follows.

Note: The following page numbers and condition numbers refer to the draft permit. These references may have changed in the final permit based on changes made during the comment period.

Comment #1:

Page 5, first paragraph, first sentence should begin as follows, "Peco Foods, Inc. operates a poultry processing plant and hatchery at 4114..."

Response to Comment #1:

This change has been implemented in the permit.

Comment #2:

Page 5, first paragraph, second sentence should begin as follows, "The plant is adding two protein..."

Response to Comment #2:

This change has been implemented in the permit.

Comment #3:

Page 6, third paragraph, second sentence, "The continuous cookers are so called because once filled and operating..."

Response to Comment #3:

This change has been implemented in the permit.

Comment #4:

Page 6, third paragraph, "Steam generated by two on-site 62.8 MMBtu/hr boilers..." Remove the 1500 hp.

Response to Comment #4:

This change has been implemented in the permit.

Comment #5:

Page 13, source description for SN-01/SN-02 - Remove references to 1500 HP and change to 62.8 MMBtu/hr and correct 62.773 to 62.8

Response to Comment #5:

This change has been implemented in the permit.

Comment #6:

Page 14, Specific Condition 4 – remove “instead” from the end of the first sentence.

Response to Comment #6:

This change has been implemented in the permit.

Comment #7:

Page 15, Specific Condition 5 – remove requirement for the sulfur content of natural gas. Pipeline quality natural gas will be essentially sulfur free.

Response to Comment #7:

This change has been implemented in the permit.

Comment #8:

Page 15, Specific Condition 5 – the SO₂ factor in the table should be corrected for No. 2 Fuel Oil (0.5% sulfur) from 7.1 to 71.0

Response to Comment #8:

This change has been implemented in the permit.

Comment #9:

Page 15, Specific Condition 5 – the PM factor in the table should be corrected for No. 6 Fuel Oil from 7.76 to 7.82

Response to Comment #9:

This change has been implemented in the permit.

Comment #10:

Page 15, Specific Condition 5 – the PM factor in the table should be footnoted for “On Spec” with ‘assumes 1% ash’

Response to Comment #10:

This change has been implemented in the permit.

Comment #11:

Please reword Specific Condition 17 as follows, “SN-01 and SN-02 are not subject to 40 CFR 63, Subpart JJJJJ-National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers Area Sources as long as the boilers use natural gas as fuel. SN-01 and SN-02 become subject to Subpart JJJJJ after the facility uses oil as fuel, except for periods of natural gas curtailment or testing purposes. The requirements of Subpart JJJJJ include, but are not limited to, Specific Conditions #18 through #27. These requirements do not

apply until after the facility uses oil as fuel, except for periods of natural gas curtailment or testing purposes. A copy of Subpart JJJJJJ.....

Response to Comment #11:

Specific Condition #17 has been changed to the following to more accurately reflect the definition of “gas-fired boiler” under Subpart JJJJJJ:

17. SN-01 and SN-02 are not subject to 40 CFR Part 63, Subpart JJJJJJ—*National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources* as long as the boilers use natural gas as fuel. SN-01 and SN-02 become subject to Subpart JJJJJJ after the facility uses oil as fuel except during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year. . The requirements of Subpart JJJJJJ include, but are not limited to, Specific Conditions #18 through #27. These requirements do not apply until after the facility become subject to Subpart JJJJJJ. A copy of Subpart JJJJJJ is included as Appendix B of this permit. [Regulation 19 §19.304, 40 CFR §63.11193, §63.11194, and §63.11195]

Responses to Comments #12 through #24 were provided by the facility.

Comment #12:

It would be helpful if a process flow diagram were included with the air permit for the ventilation streams. It is not clear which equipment or work area sources of emissions are tied to the scrubber, venturi, RTO or simply vented to atmosphere.

Response to Comment #12:

Any odor emissions from processes not captured directly and ducted to the high intensity scrubber system (venturi scrubber in series with the RTO) would become “fugitive” emissions emitted into the building confines and controlled by the room air scrubber.

Comment #13:

It is not mentioned how emissions during equipment maintenance and breakdowns would be controlled. Are these included with the “fugitive emissions” mentioned in the description? Will all the building ventilation required for personnel by OSHA be scrubbed? It is unclear in the application description.

Response to Comment #13:

See response to comment #12 concerning fugitive emissions inside the building and control by the room air scrubber. There is no specific “building ventilation” required by OSHA for plant personnel, other than indirect benefit for temperature control. In addition, OSHA related issues are not the jurisdiction of an air permit.

Comment #14:

Will there be provisions to sample or analyze streams in and out of emission control equipment for checking effectiveness of control?

Response to Comment #14:

The scrubbing system is for odor control and not for criteria pollutant emissions control. There is no quantitative metric for uncontrolled and controlled odor.

Comment #15:

Are there any controls for feather emissions from the Peco-operated part of the facility? Is this not significant PM?

Response to Comment #15:

There will be no feather discharge. All feathers are captured, water screen off of them and put in a sealed trailer and sold.

Comment #16:

The air emissions from SN-03 are not described or quantified separately in the permit.

Response to Comment #16:

Wastewater effluent emissions are quantified and are limited to GHGs (SN-03).

Comment #17:

“In each process line, the raw materials will first be reduced in size by a raw material grinder, to a size suitable for processing.”

The stream should have free liquid at this point. Will seals on the grinder be liquid-fast and will grinder be ventilated separately?

Response to Comment #17:

The seals on the grinder will be liquid fast. The grinder will not be ventilated separately. See response to #12 above concerning fugitive emissions inside the building and control by the room air scrubber.

Comment #18:

“The materials will then be moved by hydraulic pressure conveyor from the grinder to the cooker. The cooker functions to render (cook to liquefy and separate fat from solids and remove water) the raw materials. The rendered materials exiting the cooker will pass across a drainer screw to separate (drain off) the majority of the free fat from the materials. The remaining materials will then be moved by covered screw conveyor to presses that remove additional fat. The pressed material exiting the presses (known as “crax” by nature of its cake-like crunchy matrix) will then be moved by covered screw conveyor to a finishing grinder for size reduction to a meal.”

When the solid stream is cooled, will it be contained and not in contact with the atmosphere? How will the hot and cooled materials be vented?

Response to Comment #18:

The transfer of hot crax from the presses to the finish grinder will be by covered conveyor inside the process building. As the crax is ground and sorted to finished meal, it is cooled. High

intensity odor/heat is captured to the high intensity scrubber system (venturi and RTO in series) at the presses. See response to #12 above concerning fugitive emissions inside the building and control by the room air scrubber.

Comment #19:

“The ground crax exiting the finishing grinder will then be moved by covered screw conveyor to vibrating screens to size the finished protein meal product. Finished meal product that passes through the screens will be moved by covered screw conveyor to storage silos. Ground meal that is too large to pass through the screens will be diverted back to the inlet of the finishing grinder to be reground and then sent back across the screens again until all meal is reduced to the proper size and sent to storage. Stored finished meal product will be moved from the storage silos by covered screw conveyor for sale load-out to tractor-trailers.

Fat from the drainer screw and the presses will be clarified in centrifuges to separate entrained solids from the liquid fat.”

How will the equipment containing hot and cooled fat be vented?

Response to Comment #19:

High intensity odor/heat is captured and ducted to the high intensity scrubber system (venturi and RTO in series) at the presses. See response to #12 above concerning fugitive emissions inside the building and control by the room air scrubber. Finished fat is not volatile and does not emit vapors from storage tanks.

Comment #20:

“The water that will be evaporated from the raw materials as steam in each cooker will be condensed by a dedicated air-cooled condenser for each cooker. These condensers will also, by way of condensing the water saturated vapor stream, induce a vapor collapse vacuum that will maintain a slight negative pressure in the cookers. “

This statement should be reconsidered in light of non-condensables. It seems more likely that the suction provided by the venturi and RTO induction fan will be required to maintain the slight negative pressure in the cookers.

Response to Comment #20:

The process description statement is correct. The comment is correct that residual non-condensable vapors off the condensers flow to the high intensity scrubber system (venturi and RTO in series) are induced by pull from the scrubber fans, as is already described in the process description statement. However, the comment is not correct that cooker negative pressure is maintained by the fans. Cooker negative pressure is maintained by the significant vapor collapse in the condensers.

Comment #21:

“Condenser condensate (known as “stick water”), as well as miscellaneous other process waters (raw material trailer drainage, washdown, scrubber blowdown, boiler blowdown,

boiler water softener regeneration blowdown, and so on) and captured storm water, will be sent by pump and piping from the Plant to the primary Peco facility's on-site wastewater treatment system (WWTS) for treatment and subsequent disposition."

The "stick water" will be odorous like the tail gas with which it is last in contact. Will it not be deodorized separately before dilution with the other wastewater streams?

Response to Comment #21:

All "stick water" will be conveyed to the WWTS via sealed pumps and piping. Chemicals that may be used to deodorize the stick water would be detrimental to the microorganisms in the WWTS potentially inhibiting the WWTS performance.

Comment #22:

"An induction fan will pull non-condensable high-intensity malodorous tail gas vapors from the cooker condensers through a wet venturi scrubber (one scrubber will serve both lines). The venturi scrubber will cool and condense additional water and malodorous vapors, and remove particulate matter (PM) from the vapor stream, by providing a restricted area "throat" section that will take the vapor stream from a laminar flow condition to a turbulent flow condition, and introduce a recirculating water spray into the turbulence. This water spray intermixing with the turbulent vapor flow will be very effective in providing quenching and PM removal treatment to condition the vapor stream for the next step of treatment."

Will the venturi solution be separately treated with oxidation or sequester chemistry, too?

Response to Comment #22:

The purpose of the venturi scrubber is to cool and condition the air stream for presentation to the RTO, not for odor control. Makeup water for the venturi scrubber will be provided by overflow from the room air scrubber and will contain residual oxidation or sequestering chemistry.

Comment #23:

"The vapor stream exiting the venturi scrubber will then flow to a regenerative thermal oxidizer (RTO) for high temperature oxidation destruction of all malodorous compounds. The RTO will be typically operated at a temperature of 1,300 °F, well above destruction threshold of all malodorous compounds."

Turnkey RTO's describe operating temperatures of 1,500 to 1,800 °F. This is not a critical number in permitting, is it?

Response to Comment #23:

The RTO is for odor control. The commenter should not confuse oxidation temperature required for odor control with oxidation temperatures required for other RTO applications in industry (such as paint and ink solvent control). The exact operating temperature of the RTO will be determined following the start of operations.

Comment #24:

“The treated high temperature stream from the RTO combustion area will then flow to the RTO heat recovery area that will recover and store the heat from the exiting air stream and later transfer the stored heat to the incoming vapor stream. The approximate 250°F stream will then be discharged to the atmosphere at a stack emission point (EP). This RTO process is highly efficient and effective in malodor destruction.

A separate two stage cross-flow, room air scrubber system will be mounted on the Plant roof to capture and treat fugitive low-intensity malodors from within the Plant. This system will induce a slight negative pressure on the Plant process building. Treatment will be by conventional wet scrubbing with odor control chemistry used in the recirculating water. The chemistry will include pH control and oxidation or sequestration chemistry to thoroughly remove the low-intensity malodors from the air stream. The treated air stream will then be discharged to the atmosphere at a stack EP.”

Can the performance of this odor control equipment be monitored if need be?

Response to Comment #24:

It is well known that the determination of odor intensity is very subjective and varies from individual to individual.

ADEQ OPERATING AIR PERMIT

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

Permit No. : 2232-AOP-R0

IS ISSUED TO:

Peco Foods, Inc.
4114 Highway 67 South
Pocahontas, AR 72455
Randolph County
AFIN: 61-01017

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

DEC 17 2014

AND

DEC 16 2019

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

Signed:



Mike Bates
Chief, Air Division

DEC 17 2014

Date

Peco Foods, Inc.
Permit #: 2232-AOP-R0
AFIN: 61-01017

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Permit #: 2232-AOP-R0
AFIN: 61-01017

List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO _x	Nitrogen Oxide
PM	Particulate Matter
PM ₁₀	Particulate Matter Smaller Than Ten Microns
SNAP	Significant New Alternatives Program (SNAP)
SO ₂	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

Peco Foods, Inc.
Permit #: 2232-AOP-R0
AFIN: 61-01017

SECTION I: FACILITY INFORMATION

PERMITTEE: Peco Foods, Inc.
AFIN: 61-01017
PERMIT NUMBER: 2232-AOP-R0
FACILITY ADDRESS: 4114 Highway 67 South
Pocahontas, AR 72455
MAILING ADDRESS: P. O. Box 1760
Tuscaloosa, AL 35403
COUNTY: Randolph County
CONTACT NAME: Benny Bishop
CONTACT POSITION: Construction Manager
TELEPHONE NUMBER: 205-345-4571
REVIEWING ENGINEER: Alexander Sudibjo
UTM North South (Y): Zone 15: 4009645 m
UTM East West (X): Zone 15: 684103 m

SECTION II: INTRODUCTION

Summary of Permit Activity

Peco Foods, Inc. operates a poultry processing plant and hatchery at 4114 Highway 67 South, Pocahontas, Randolph County, AR. The plant is adding two protein conversion processing lines, each consisting of raw material preparation, cooking, and separation equipment. This is the initial Title V Operating Air Permit for the facility. Emissions will come from two (2) 62.8 MMBtu/hr boilers (SN-01 and SN-02), Wastewater Effluent (SN-03), two cooker lines (SN-04), an emergency generator (SN-05), and three (3) 3.2 MMBtu/hr hatchery boilers (SN-06, SN-07, and SN-08). The facility will do monthly calculations of PM and SO₂ emissions to stay below the PSD major source limit. The facility's permitted annual emissions are 219.9 tpy, 174.8 tpy, 249.0 tpy, 4.9 tpy, 21.8 tpy, and 178.4 tpy for PM, PM₁₀, SO₂, VOC, CO, and NO_x respectively.

Process Description

Griffin Industries LLC (Griffin) will take the poultry by-products generated by the Peco Foods, Inc. (Peco) primary poultry processing plant for subsequent processing into various protein meal and fat products. In partnership with Peco, Griffin will operate a protein conversion plant (hereinafter Plant) immediately adjacent to (on the facility site of) the Peco plant. The Plant will process certain of these by-products including meat, bone, and offal by-products; other by-products (e.g. blood and feathers) will be sent off-site to other Griffin facilities for processing.

The Plant operates two protein conversion processing lines, each consisting of raw material preparation, cooking, and separation equipment. The design process capacity of each line will be 43,100 pounds per hour (lb/hr) of poultry by-product raw material (assuming 65% water content), for a total Plant design capacity of 86,200 lb/hr of raw material. Each line may achieve actual raw material production rates higher than 43,100 lb/hr as this will vary according to raw material moisture content and will produce protein meal and fat product rates according to this raw moisture content, and residual protein and fat content.

The poultry by-product raw materials will be transferred from the primary Peco-operated processing plant to the Griffin-operated Plant by tractor-trailer. The materials will be offloaded from the trailers into two (2) receiving pits located within the Plant building confines. The materials will then be moved by inclined screw conveyor from the pits to the processing lines.

In each process line, the raw materials will first be reduced in size by a raw material grinder, to a size suitable for processing. The materials will then be moved by hydraulic pressure conveyor from the grinder to the cooker. The cooker functions to render (cook to liquefy and separate fat from solids and remove water) the raw materials. The rendered materials exiting the cooker will pass across a drainer screw to separate (drain off) the majority of the free fat from the materials. The remaining materials will then be moved by covered screw conveyor to presses that remove additional fat. The pressed material exiting the presses (known as "crax" by nature of its cake-like crunchy matrix) will then be moved by covered screw conveyor to a finishing grinder for size reduction to a meal. The ground crax exiting the finishing grinder will then be moved by

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covered screw conveyor to vibrating screens to size the finished protein meal product. Finished meal product that passes through the screens will be moved by covered screw conveyor to storage silos. Ground meal that is too large to pass through the screens will be diverted back to the inlet of the finishing grinder to be reground and then sent back across the screens again until all meal is reduced to the proper size and sent to storage. Stored finished meal product will be moved from the storage silos by covered screw conveyor for sale load-out to tractor-trailers.

Fat from the drainer screw and the presses will be clarified in centrifuges to separate entrained solids from the liquid fat. The solids from the centrifuges will be moved by covered screw conveyor back to the processing line, and the clarified fat will be pumped to storage (tankage). Stored finished fat will be pumped from the tankage for sale load-out to tractor-trailer tankers.

Griffin utilizes an efficient continuous cooking process; the line equipment is manufactured by specialized rendering equipment suppliers. The continuous cookers are so called because once filled and operating, raw materials are continuously fed into the cooker inlet while rendered materials are continuously removed from the cooker outlet. Steam generated by two on-site 62.8 MMBtu/hr boilers will be used to indirectly heat and render the raw materials in the cookers. The temperature of the rendered materials leaving the cooker is typically 290 °F to 300 °F to ensure thorough cooking and disinfection of the materials.

The water that will be evaporated from the raw materials as steam in each cooker will be condensed by a dedicated air-cooled condenser for each cooker. These condensers will also, by way of condensing the water saturated vapor stream, induce a vapor collapse vacuum that will maintain a slight negative pressure in the cookers. Condenser condensate (known as “stick water”), as well as miscellaneous other process waters (raw material trailer drainage, washdown, scrubber blowdown, boiler blowdown, boiler water softener regeneration blowdown, and so on) and captured storm water, will be sent by pump and piping from the Plant to the primary Peco facility’s on-site wastewater treatment system (WWTS) for treatment and subsequent disposition.

An induction fan will pull non-condensable high-intensity malodorous tail gas vapors from the cooker condensers through a wet venturi scrubber (one scrubber will serve both lines). The venturi scrubber will cool and condense additional water and malodorous vapors, and remove particulate matter (PM) from the vapor stream, by providing a restricted area “throat” section that will take the vapor stream from a laminar flow condition to a turbulent flow condition, and introduce a recirculating water spray into the turbulence. This water spray intermixing with the turbulent vapor flow will be very effective in providing quenching and PM removal treatment to condition the vapor stream for the next step of treatment.

The vapor stream exiting the venturi scrubber will then flow to a regenerative thermal oxidizer (RTO) for high temperature oxidation destruction of all malodorous compounds. The RTO will be typically operated at a temperature of 1,300 °F, well above destruction threshold of all malodorous compounds. The treated high temperature stream from the RTO combustion area will then flow to the RTO heat recovery area that will recover and store the heat from the exiting air stream and later transfer the stored heat to the incoming vapor stream. The approximate

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250°F stream will then be discharged to the atmosphere at a stack emission point (EP). This RTO process is highly efficient and effective in malodor destruction.

A separate two stage cross-flow, room air scrubber system will be mounted on the Plant roof to capture and treat fugitive low-intensity malodors from within the Plant. This system will induce a slight negative pressure on the Plant process building. Treatment will be by conventional wet scrubbing with odor control chemistry used in the recirculating water. The chemistry will include pH control and oxidation or sequestration chemistry to thoroughly remove the low-intensity malodors from the air stream. The treated air stream will then be discharged to the atmosphere at a stack EP.

The Griffin-operated protein conversion Plant will therefore have four (4) EPs to be included in the air permit: each of the two (2) boiler stacks, the RTO, and room air scrubber stacks. Covered screw conveyance of in-process and finished meals are not required to be permitted due to the large particulate size and high fat content of the meal. The hatchery operates three (3) 3.2 MMBtu/hr natural gas-fired boilers (SN-06, SN-07, and SN-08) that will provide heat in the form of steam to the hatchery building. The facility also operates a 2.5 MMBtu/hr diesel-fueled emergency generator (SN-05).

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective June 18, 2010
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective September 13, 2014
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective November 18, 2012
40 CFR Part 60, Subpart Dc— <i>Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</i>
¹ 40 CFR Part 63, Subpart JJJJJ— <i>National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources</i>
40 CFR Part 60, Subpart IIII— <i>Standards of Performance for Stationary Compression Ignition Internal Combustion Engine</i>

¹SN-01 and SN-02 are not subject to Subpart JJJJJ until after the facility uses oil as fuel.

Emission Summary

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

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	59.7	219.9
		PM ₁₀	47.4	174.8
		SO ₂	68.1	249.0
		VOC	1.8	4.9
		CO	6.2	21.8
		NO _x	51.1	178.4
HAPs *		Formaldehyde	0.07	0.23
		Hexane	0.02	0.09
		POM	0.01	0.02
		Arsenic Compounds	0.10	0.38
		Beryllium Compounds	0.01	0.01
		Cadmium Compounds	0.01	0.04
		Cobalt Compounds	0.01	0.02
		Lead Compounds	0.01	0.01
		Manganese Compounds	0.08	0.23
		Mercury Compounds	0.01	0.01
	Nickel Compounds	0.08	0.27	
Air Contaminants **		H ₂ S	0.7	3.0
		NH ₃	5.1	22.1
01	Boiler 1	PM	29.2	216.0 ¹
		PM ₁₀	23.2	172.2 ¹
		SO ₂	33.5	248.5 ¹
		VOC	0.5	3.4 ¹
		CO	2.4	18.0 ¹
		NO _x	23.2	173.3 ¹
		Formaldehyde	0.03	0.22 ¹
		POM	1.55e-3	0.02 ¹
		Arsenic Compounds	0.05	0.38 ¹
		Beryllium Compounds	1.88e-4	1.65e-3 ¹
		Cadmium Compounds	4.23e-3	0.04 ¹
Cobalt Compounds	2.54e-3	0.02 ¹		

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Lead Compounds	6.36e-4	4.95e-3 ¹
		Manganese Compounds	0.04	0.23 ¹
		Mercury Compounds	1.88e-4	1.65e-3 ¹
		Nickel Compounds	0.04	0.27 ¹
02	Boiler 2	PM	29.2	- ¹
		PM ₁₀	23.2	- ¹
		SO ₂	33.5	- ¹
		VOC	0.5	- ¹
		CO	2.4	- ¹
		NO _x	23.2	- ¹
		Formaldehyde	0.03	- ¹
		POM	1.55e-3	- ¹
		Arsenic Compounds	0.05	- ¹
		Beryllium Compounds	1.88e-4	- ¹
		Cadmium Compounds	4.23e-3	- ¹
		Cobalt Compounds	2.54e-3	- ¹
		Lead Compounds	6.36e-4	- ¹
		Manganese Compounds	0.04	- ¹
Mercury Compounds	1.88e-4	- ¹		
Nickel Compounds	0.04	- ¹		
04	Cooking Operation (2 Lines)	PM	0.8	3.5
		PM ₁₀	0.5	2.2
		VOC	0.3	1.1
		H ₂ S	0.7	3.0
		NH ₃	5.1	22.1
05	Diesel-Fueled Emergency Generator (2.5 MMBtu/hr)	PM	0.2	0.1
		PM ₁₀	0.2	0.1
		SO ₂	0.8	0.2
		VOC	0.2	0.1
		CO	0.5	0.2
		NO _x	3.5	0.9
		Formaldehyde	2.91e-3	7.27e-4
POM	2.04e-4	5.11e-5		
06	Hatchery Boiler #1	PM	0.1	0.1
		PM ₁₀	0.1	0.1
		SO ₂	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	1.2
		NO _x	0.4	1.4
		Formaldehyde	2.34e-4	1.02e-3

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Hexane	5.62e-3	0.03
		POM	3.94e-6	1.72e-5
		Arsenic Compounds	6.24e-7	2.73e-6
		Beryllium Compounds	3.74e-8	1.64e-7
		Cadmium Compounds	3.43e-6	1.5e-5
		Cobalt Compounds	2.62e-7	1.15e-6
		Manganese Compounds	1.19e-6	5.19e-6
		Mercury Compounds	8.11e-7	3.55e-6
		Nickel Compounds	6.55e-6	2.87e-5
07	Hatchery Boiler #2	PM	0.1	0.1
		PM ₁₀	0.1	0.1
		SO ₂	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	1.2
		NO _x	0.4	1.4
		Formaldehyde	2.34e-4	1.02e-3
		Hexane	5.62e-3	0.03
		POM	3.94e-6	1.72e-5
		Arsenic Compounds	6.24e-7	2.73e-6
		Beryllium Compounds	3.74e-8	1.64e-7
		Cadmium Compounds	3.43e-6	1.5e-5
		Cobalt Compounds	2.62e-7	1.15e-6
Manganese Compounds	1.19e-6	5.19e-6		
Mercury Compounds	8.11e-7	3.55e-6		
Nickel Compounds	6.55e-6	2.87e-5		
08	Hatchery Boiler #3	PM	0.1	0.1
		PM ₁₀	0.1	0.1
		SO ₂	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	1.2
		NO _x	0.4	1.4
		Formaldehyde	2.34e-4	1.02e-3
		Hexane	5.62e-3	0.03
		POM	3.94e-6	1.72e-5
		Arsenic Compounds	6.24e-7	2.73e-6
		Beryllium Compounds	3.74e-8	1.64e-7
		Cadmium Compounds	3.43e-6	1.5e-5
		Cobalt Compounds	2.62e-7	1.15e-6
Manganese Compounds	1.19e-6	5.19e-6		
Mercury Compounds	8.11e-7	3.55e-6		

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EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Nickel Compounds	6.55e-6	2.87e-5

*HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.

**Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

¹Annual emission limits are combined for SN-01 and SN-02

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SECTION III: PERMIT HISTORY

Permit #2232-AOP-R0 will be the initial Title V Operating Air Permit for this facility.

SECTION IV: SPECIFIC CONDITIONS

SN-01 & SN-02
 Boilers 1 & 2

Source Description

The facility operates two (2) 62.8 MMBtu/hr boilers to indirectly heat and render the raw materials in the cooker. Each burner for the boilers is equipped with low NOx combustion technology. The boilers are equipped to use the following as fuel: Natural Gas, Low Sulfur Diesel, No.2 Fuel Oil, No.6 Fuel Oil, “On-spec” Used Oil, and Processed Fat.

Specific Conditions

- The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #5. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
01	Boiler 1	PM ₁₀	23.2	172.2 ¹
		SO ₂	33.5	248.5 ¹
		VOC	0.5	3.4 ¹
		CO	2.4	18.0 ¹
		NO _x	23.2	173.3 ¹
02	Boiler 2	PM ₁₀	23.2	- ¹
		SO ₂	33.5	- ¹
		VOC	0.5	- ¹
		CO	2.4	- ¹
		NO _x	23.2	- ¹

¹Annual emission limits are combined for SN-01 and SN-02.

- The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #5. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
01	Boiler 1	PM	29.2	216.0*
		Formaldehyde	0.03	0.22*
		POM	1.55e-3	0.02*
		Arsenic Compounds	0.05	0.38*
		Beryllium Compounds	1.88e-4	1.65e-3 ¹
		Cadmium Compounds	4.23e-3	0.04 ¹

SN	Description	Pollutant	lb/hr	tpy
		Cobalt Compounds	2.54e-3	0.02 ¹
		Lead Compounds	6.36e-4	4.95e-3 ¹
		Manganese Compounds	0.04	0.23 ¹
		Mercury Compounds	1.88e-4	1.65e-3 ¹
		Nickel Compounds	0.04	0.27 ¹
02	Boiler 2	PM	29.2	- ¹
		Formaldehyde	0.03	- ¹
		POM	1.55e-3	- ¹
		Arsenic Compounds	0.05	- ¹
		Beryllium Compounds	1.88e-4	- ¹
		Cadmium Compounds	4.23e-3	- ¹
		Cobalt Compounds	2.54e-3	- ¹
		Lead Compounds	6.36e-4	- ¹
		Manganese Compounds	0.04	- ¹
		Mercury Compounds	1.88e-4	- ¹
		Nickel Compounds	0.04	- ¹

¹Annual emission limits are combined for SN-01 and SN-02.

3. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9.

SN	Fuel Type	Limit	Regulatory Citation
01 & 02	Natural Gas	5%	Regulation 18 §18.501
	Low Sulfur Diesel	20%	Regulation 19 §19.503
	No. 2 Fuel Oil	20%	Regulation 19 §19.503
	No. 6 Fuel Oil	20%	Regulation 19 §19.503
	“On Spec” Used Oil	20%	Regulation 19 §19.503
	Processed Fat	20%	Regulation 19 §19.503

4. When SN-01 or SN-02 uses Low Sulfur Diesel, No. 2 Fuel Oil, No. 6 Fuel Oil, “On Spec” Used Oil, or Processed Fat as fuel, daily observations of the opacity from SN-01 or SN-02 shall be conducted by a person trained but not necessarily certified in EPA Reference Method 9. If visible emissions in excess of the permitted levels are detected, the permittee shall immediately take action to identify the cause of the visible emissions in excess of the permit limit, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated

monthly, kept on site, and made available to Department personnel upon request.
 [Regulation 18 §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

- a. The date and time of the observation.
 - b. If visible emissions which appeared to be above the permitted limit were detected.
 - c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
 - d. The name of the person conducting the opacity observations.
5. The permittee shall maintain monthly records of fuel burned by SN-01 and SN-02 including the type of fuels burned by SN-01 and SN-02, the quantity of fuel burned, all shipment of fuel, and the sulfur content of each non-natural gas fuel. The permittee shall then calculate and keep records of the monthly PM and SO₂ emissions from SN-01 and SN-02 based on the fuel usage records and the following emission factors or from emission factors derived from the stack test, whichever is higher. The rolling 12 month total of PM and SO₂ emissions shall not exceed the limit set in Specific Conditions #1 and #2. 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, made available to Department personnel upon request, and submitted in accordance with General Provision #7.
 [Regulation 19 §19.705 et seq., 40 CFR Part 52, Subpart E, Regulation 18 §18.1004, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Fuel burned	Pollutant	Emission Factors
Natural Gas	PM	7.6 lb/MMscf
	SO ₂	0.6 lb/MMscf
Low Sulfur Diesel (0.05% sulfur)	PM	2.0 lb/Mgal
	SO ₂	7.1 lb/Mgal
No. 2 Fuel Oil (0.5% sulfur)	PM	2.0 lb/Mgal
	SO ₂	71.0 lb/Mgal
No. 6 Fuel Oil (0.5% sulfur)	PM	7.82 lb/Mgal
	SO ₂	78.5 lb/Mgal
"On Spec" Used Oil* (0.5% sulfur)	PM	64.0 lb/Mgal
	SO ₂	73.5 lb/Mgal
Processed Fat	PM	1.26 lb/Mgal
	SO ₂	0.04 lb/Mgal

* 1% ash content

6. The permittee shall test particulate matter emissions from Boiler 1 and Boiler 2 (SN-01 and SN-02) once every five years. The test for particulate matter will take place only in years in which No. 6 Fuel Oil or "On Spec" Used Oil is being combusted. Testing shall be performed in accordance with Plantwide Condition #3. The permittee will perform the

PM test using EPA Reference Methods 5 and 202. The permittee will perform PM₁₀ test using either EPA Reference Methods 201A and 202 or 5 and 202. By using Method 5 and 202 for PM₁₀, the facility will assume all collected particulate is PM₁₀. The permittee shall test both Boiler 1 and Boiler 2 stacks. The runs for Boiler 1 stack shall be averaged together. The runs for Boiler 2 stack shall be averaged together. The average run for Boiler 1 stack shall be added to the average run for Boiler 2 to demonstrate compliance with the particulate matter emission limit. Upon failure of a stack test, the permittee shall stack test annually at either of the two Boilers until two consecutive years are below the limits specified in Specific Condition #2. During the test, the permittee shall operate the plant within 10 percent of the rated throughput capacity. If 90 percent of the rated throughput capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. [Regulation 19, §19.702 and 40 CFR Part 52 Subpart E]

7. The permittee shall construct the stacks for SN-01 and SN-02 to the following specification or better. The permittee shall measure the stack gas temperature and stack gas velocity of both stacks after the construction of SN-01 and SN-02. [Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Stack Parameter	Parameter Specification
Stack Height	40 ft
Inside Stack Dimensions	4.0 ft
Stack Gas Temperature	550 °F
Stack Gas Velocity	52 ft/sec

8. If the facility does not construct the boilers with the ability to combust a fuel permitted within the timelines of Plantwide Condition #2, authorization in this permit for that fuel use will lapse. [Regulation 19 §19.410(B) and 40 CFR Part 52, Subpart E]

NSPS Dc Conditions

9. SN-01 and SN-02 are subject to 40 CFR Part 60, Subpart Dc—*Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*. The requirements of Subpart Dc include, but are not limited to, Specific Conditions #10 through #16. A copy of Subpart Dc is included as Appendix A of this permit. [Regulation 19 §19.304 and 40 CFR §60.40c]
10. The permittee shall not combust oil that contains greater than 0.5 weight percent sulfur at SN-01 and SN-02. Compliance with the fuel oil sulfur limits may be determined based on a certification from the fuel supplier as described in Specific Condition #11, as applicable. This limit applies at all times, including periods of startup, shutdown, and malfunction. [Regulation 19 §19.304, 40 CFR §60.42c(d), §60.42c(h), and §60.44c(h)]

11. Fuel supplier certification shall include the following information: [Regulation 19 §19.304 and 40 CFR §60.48c(f)]
 - a. 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.
 - b. 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.
 - c. 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.
 - d. 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.
12. The permittee shall submit notification of the date of construction or reconstruction and actual startup, as provided by 40 CFR §60.7. This notification shall include: [Regulation 19 §19.304 and 40 CFR §60.48c(a)]
 - a. The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.
 - b. 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.
 - c. 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.
13. The permittee shall keep the following records and submit reports to the Department as applicable: [Regulation 19 §19.304 and 40 CFR §60.48c(e)]
 - a. Calendar dates covered in the reporting period.
 - b. 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.
 - c. 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.
 - d. 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.
 - e. 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.
 - f. Identification of the F factor used in calculations, method of determination, and type of fuel combusted.
 - g. If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under Specific Condition #11, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the permittee that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

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14. The permittee shall record the amount of each fuel combusted during each operating day. As an alternative to this requirement, if the permittee combusts only natural gas, wood, fuels using fuel certification in Specific Condition #11 to demonstrate compliance with the SO₂ standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels, the permittee may elect to record and maintain records of the amount of each fuel combusted during each calendar month. [Regulation 19 §19.304 and 40 CFR §60.48c(g)]
15. The permittee shall maintain all records required under Subpart Dc for a period of two years following the date of such record. [Regulation 19 §19.304 and 40 CFR §60.48c(i)]
16. The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Department and shall be postmarked by the 30th day following the end of the reporting period. [Regulation 19 §19.304 and 40 CFR §60.48c(j)]

NESHAP JJJJJ Conditions

17. SN-01 and SN-02 are not subject to 40 CFR Part 63, Subpart JJJJJ—*National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources* as long as the boilers use natural gas as fuel. SN-01 and SN-02 become subject to Subpart JJJJJ after the facility uses oil as fuel except during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year. . The requirements of Subpart JJJJJ include, but are not limited to, Specific Conditions #18 through #27. These requirements do not apply until after the facility become subject to Subpart JJJJJ. A copy of Subpart JJJJJ is included as Appendix B of this permit. [Regulation 19 §19.304, 40 CFR §63.11193, §63.11194, and §63.11195]
18. The permittee shall 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, the permittee shall follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. [Regulation 19 §19.304 and 40 CFR §63.11201(b)]
19. If the permittee 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 emission limit under Subpart JJJJJ and that do not use a post-combustion technology (except a wet scrubber) to reduce particulate matter (PM) or sulfur dioxide emissions, the permittee is not subject to the PM emission standard of Subpart JJJJJ providing the permittee monitors and records on a monthly basis the type of fuel combusted. If the permittee intend to burn a new type of fuel or fuel mixture that does not meet this requirement, the permittee shall conduct a performance test within 60 days of burning the

new fuel. This standard applies at all times SN-01 and SN-02 are operating, except during periods of startup and shutdown as defined in 40 CFR §63.11237, during which time the permittee shall comply only with Specific Condition #18. [Regulation 19 §19.304, 40 CFR §63.11201(a), and §63.11210(e)]

20. At all times the permittee shall operate and maintain SN-01 and SN-02, 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 the permittee 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 Department 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. [Regulation 19 §19.304 and 40 CFR §63.11205(a)]
21. The permittee shall conduct a performance tune-up according to Specific Condition #22 and submit a signed statement in the Notification of Compliance Status report that indicates that the permittee conducted a tune-up of the boiler. The permittee shall complete the applicable biennial tune-up as specified in Specific Condition #22 no later than 25 months after the initial startup of SN-01 and SN-02. [Regulation 19 §19.304 and 40 CFR §63.11214(b)]
22. The permittee shall 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. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. The first biennial tune-up must be no later than 25 months after the initial startup of SN-01 and SN-02. The permittee shall conduct the performance tune-up according to the following section: [Regulation 19 §19.304 and 40 CFR §63.11223]
 - a. 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.
 - b. 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.
 - c. 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.

- d. 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.
 - e. 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.
 - f. Maintain on-site and submit, if requested by the Department, a report containing the following information:
 - 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.
 - g. 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.
23. The permittee shall submit the following notifications to the Department: [Regulation 19 §19.304 and 40 CFR §63.11225 (a)]
- a. The permittee shall submit all of the notifications in 40 CFR §§63.7(b); 63.8(e) and (f); and 63.9(b) through (e), (g), and (h) that apply to the facility by the dates specified in those sections.
 - b. An Initial Notification must be submitted within 120 days after the source becomes subject to the standard.
 - c. If the permittee is required to conduct a performance stack test the permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance stack test is scheduled to begin.
 - d. The permittee shall submit the Notification of Compliance Status no later than 120 days after SN-01 or SN-02 become subject to 40 CFR Part 63, Subpart JJJJJ. If the permittee must conduct a performance stack test, the permittee shall submit the Notification of Compliance Status within 60 days of completing the performance stack test. The permittee shall submit the Notification of Compliance Status in accordance with the following section. The Notification of Compliance Status must include the information and certification(s) of compliance in the following 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. 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.
 - e. If the permittee is using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, the permittee shall 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.
24. The permittee shall prepare, by March 1 of each year, and submit to the Department upon request, an annual compliance certification report for the previous calendar year containing the following information: [Regulation 19 §19.304 and 40 CFR §63.11225(b)]
 - a. Company name and address.
 - b. 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. The 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 40 CFR §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 40 CFR §§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.”

25. The permittee shall maintain the following records. These records shall be in a form suitable and readily available for expeditious review. The permittee shall keep each record for 5 years following the date of each recorded action. The permittee shall 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. The permittee may keep the records off site for the remaining 3 years.
[Regulation 19 §19.304, 40 CFR §63.11225(c), and §63.11225(d)]
- a. The permittee shall keep a copy of each notification and report that were submitted to comply with 40 CFR Part 63, Subpart JJJJJ and all documentation supporting any Initial Notification or Notification of Compliance Status that were submitted.
 - b. The permittee shall keep records that 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 to document conformance with the tune-ups required by Specific Conditions #21 and #22.
 - c. Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.
 - d. Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in Specific Condition #20, including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.
 - e. The permittee shall keep the following records 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).
26. The permittee shall submit, within 60 days after the date of completing each performance test (defined in 40 CFR §63.2) as required by Subpart JJJJJ, the results of the performance tests, including any associated fuel analyses, required by Subpart JJJJJ to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to

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WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator at the appropriate address listed in 40 CFR §63.13. [Regulation 19 §19.304, 40 CFR §63.11225(c), and §63.11225(e)]

27. If the permittee 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 Subpart JJJJJ, in the boiler becoming subject to Subpart JJJJJ, or in the boiler switching out of Subpart JJJJJ due to a change to 100 percent natural gas, or the permittee have taken a permit limit that resulted in the facility being subject to subpart JJJJJ, the permittee shall provide notice of the date upon which the permittee switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify: [Regulation 19 §19.304 and 40 CFR §63.11225(g)]
- a. 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.
 - b. The date upon which the fuel switch, physical change, or permit limit occurred.

SN-04
 Cooking Operation

Source Description

The facility operates two protein conversion processing lines, each consisting of raw material preparation, cooking, and separation equipment. The design process capacity of each line will be 43,100 pounds per hour (lb/hr) of poultry by-product raw material (assuming 65% water content), for a total Plant design capacity of 86,200 lb/hr of raw material. Each line may achieve actual raw material production rates higher than 43,100 lb/hr as this will vary according to raw material moisture content and will produce protein meal and fat product rates according to this raw moisture content, and residual protein and fat content.

Specific Conditions

28. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions #32 and #33. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
04	Cooking Operation (2 Lines)	PM ₁₀	0.5	2.2
		VOC	0.3	1.1

29. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions #32 and #33. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
04	Cooking Operation (2 Lines)	PM	0.8	3.5
		H ₂ S	0.7	3.0
		NH ₃	5.1	22.1

30. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9.

SN	Limit	Regulatory Citation
04	5%	Regulation 18 §18.501

31. Monthly observations of the opacity from SN-04 shall be conducted by a person trained but not necessarily certified in EPA Reference Method 9. If visible emissions in excess of the permitted levels are detected, the permittee shall immediately take action to

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- identify the cause of the visible emissions in excess of the permit limit, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated monthly, kept on site, and made available to Department personnel upon request. [Regulation 18 §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
- a. The date and time of the observation.
 - b. If visible emissions which appeared to be above the permitted limit were detected.
 - c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
 - d. The name of the person conducting the opacity observations.
32. The permittee shall not process more than 73,584 tons of poultry by-product raw materials at SN-04 per rolling 12 month period. [Regulation 19 §19.705 et seq., 40 CFR Part 52, Subpart E, Regulation 18 §18.1004, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
33. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #32. 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, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Regulation 19 §19.705 et seq., 40 CFR Part 52, Subpart E, Regulation 18 §18.1004, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-05
 Emergency Generator

Source Description

The facility operates a 2.5 MMBtu/hr diesel-fueled emergency generator.

Specific Conditions

34. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions #38 and #39. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
05	Diesel-Fueled Emergency Generator (2.5 MMBtu/hr)	PM ₁₀	0.2	0.1
		SO ₂	0.8	0.2
		VOC	0.2	0.1
		CO	0.5	0.2
		NO _x	3.5	0.9

35. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions #38 and #39. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
05	Diesel-Fueled Emergency Generator (2.5 MMBtu/hr)	PM	0.2	0.1
		Formaldehyde	2.91e-3	7.27e-4
		POM	2.04e-4	5.11e-5

36. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9.

SN	Limit	Regulatory Citation
05	5%	Regulation 18 §18.501

37. Annual observations of the opacity from SN-05 shall be conducted by a person trained but not necessarily certified in EPA Reference Method 9. If visible emissions in excess of the permitted levels are detected, the permittee shall immediately take action to identify the cause of the visible emissions in excess of the permit limit, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain

records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated monthly, kept on site, and made available to Department personnel upon request. [Regulation 18 §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

- a. The date and time of the observation.
 - b. If visible emissions which appeared to be above the permitted limit were detected.
 - c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
 - d. The name of the person conducting the opacity observations.
38. The permittee shall not operate the emergency generator, SN-05, in excess of 500 total hours (emergency and non-emergency) per rolling 12 month period in order to demonstrate compliance with the annual emission rate limits. Emergency operation in excess of these hours may be allowable but shall be reported and will be evaluated in accordance with Regulation 19 §19.602 and other applicable regulations. [Regulation 19 §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]
39. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #38. 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, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]

NSPS IIII Conditions

40. The emergency generator (SN-05) is subject to provisions of 40 CFR Part 63, Subpart *ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*. SN-05 meet the requirements of Subpart *ZZZZ* by complying with the requirements of 40 CFR Part 60, Subpart IIII—*Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*. A copy of and Subpart IIII is provided in Appendix C of this permit. [§19.304 of Regulation 19, 40 CFR §63.6585 and 40 CFR §60.4200]
41. The permittee shall install a non-resettable hour meter and recording the hours of operation of SN-05. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. The permittee shall keep records of the notification of the emergency situation, and the date of engine operation for these purposes. If SN-05 is used for the purposes specified in Specific Condition 43.a.ii, 43.a.iii, or 43.b.ii, the permittee shall keep records of the notification of the emergency situation, the date, start time, and end time of engine operation for these purposes.

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[§19.304 and §19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311 and 40 CFR §60.4209]

42. SN-05 shall meet the following emission standard. The permittee shows compliance with this condition by purchasing an engine certified to these standards. The permittee may opt to conduct a performance test instead to meet these standards by following procedures set in 40 CFR §60.4212. [§19.304 of Regulation 19, 40 CFR §60.4202,, §60.4205, and §89.112]

SN	Pollutant	Emission Standard (g/kW-hr)
05	NMHC + NO _x	4.0
	CO	3.5
	PM	0.20

43. The permittee shall only operate SN-05 for emergency operation except for the situations described in the following section. If the permittee fails to operate SN-05 according to the following requirements, it will not be considered an emergency engine under 40 CFR Part 60, Subpart IIII and must meet all requirements for non-emergency engines. [§19.304 of Regulation 19 and 40 CFR §60.4211]
- a. The permittee may operate SN-05 for any combination of the purposes specified in the following section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by item (b) of this Condition counts as part of the 100 hours per calendar year allowed by this item (a).
 - i. SN-05 may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.
 - ii. SN-05 may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see 40 CFR §63.14), or other authorized entity as determined by the Reliability

Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

- iii. SN-05 may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

- b. SN-05 may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response allowed by item (a). Except as provided in the following section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.
 - i. Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.
 - ii. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:
 - 1. The engine is dispatched by the local balancing authority or local transmission and distribution system operator.
 - 2. The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
 - 3. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
 - 4. The power is provided only to the facility itself or to support the local transmission and distribution system.
 - 5. The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

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44. The permittee shall use diesel fuel that meets the following requirements. Any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. [§19.304 of Regulation 19, 40 CFR §60.4207, and §80.510]
 - a. A maximum sulfur content of 15 ppm; and
 - b. A minimum cetane index of 40; or
 - c. A maximum aromatic content of 35 volume percent.
45. The permittee shall operate and maintain SN-05 and any after-treatment control device according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [§19.304 of Regulation 19 and 40 CFR §60.4211]
46. If SN-05 is used for the purposes specified in Specific Condition 43.a.ii, 43.a.iii, or 43.b.ii, the permittee shall submit an annual report according to the following requirements: [§19.304 of Regulation 19, 40 and 40 CFR §60.4214]
 - a. The report must contain the following information:
 - i. Company name and address where the engine is located.
 - ii. Date of the report and beginning and ending dates of the reporting period.
 - iii. Engine site rating and model year.
 - iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
 - v. Hours operated for the purposes specified in Specific Condition 43.a.ii and 43.a.iii, including the date, start time, and end time for engine operation for the purposes specified in Specific Condition 43.a.ii and 43.a.iii.
 - vi. Number of hours the engine is contractually obligated to be available for the purposes specified in Specific Condition 43.a.ii and 43.a.iii.
 - vii. Hours spent for operation for the purpose specified in Specific Condition 43.b.ii, including the date, start time, and end time for engine operation for the purposes specified in Specific Condition 43.b.ii. The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.
 - viii. If there were no deviations from the fuel requirements in Specific Condition 44, a statement that there were no deviations from the fuel requirements during the reporting period.
 - ix. If there were deviations from the fuel requirements in Specific Condition 44, information on the number, duration, and cause of deviations, and the corrective action taken.
 - b. The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each

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calendar year must be submitted no later than March 31 of the following calendar year.

- c. The annual report must be submitted electronically using the subpart specific reporting form in 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 report must be submitted to the Administrator at the appropriate address listed in 40 CFR §63.13.

SN-06, SN-07, & SN-08
 Hatchery Boilers

Source Description

The facility operates three (3) 3.2 MMBtu/hr boilers to provide heat in the form of steam to the hatchery building.

Specific Conditions

47. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #50. [Regulation 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
06	Hatchery Boiler #1	PM ₁₀	0.1	0.1
		SO ₂	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	1.2
		NO _x	0.4	1.4
07	Hatchery Boiler #2	PM ₁₀	0.1	0.1
		SO ₂	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	1.2
		NO _x	0.4	1.4
08	Hatchery Boiler #3	PM ₁₀	0.1	0.1
		SO ₂	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	1.2
		NO _x	0.4	1.4

48. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #50. [Regulation 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
06	Hatchery Boiler #1	PM	0.1	0.1
		Formaldehyde	2.34e-4	1.02e-3
		Hexane	5.62e-3	0.03
		POM	3.94e-6	1.72e-5
		Arsenic Compounds	6.24e-7	2.73e-6
		Beryllium Compounds	3.74e-8	1.64e-7
		Cadmium Compounds	3.43e-6	1.5e-5

SN	Description	Pollutant	lb/hr	tpy
		Cobalt Compounds	2.62e-7	1.15e-6
		Manganese Compounds	1.19e-6	5.19e-6
		Mercury Compounds	8.11e-7	3.55e-6
		Nickel Compounds	6.55e-6	2.87e-5
07	Hatchery Boiler #2	PM	0.1	0.1
		Formaldehyde	2.34e-4	1.02e-3
		Hexane	5.62e-3	0.03
		POM	3.94e-6	1.72e-5
		Arsenic Compounds	6.24e-7	2.73e-6
		Beryllium Compounds	3.74e-8	1.64e-7
		Cadmium Compounds	3.43e-6	1.5e-5
		Cobalt Compounds	2.62e-7	1.15e-6
		Manganese Compounds	1.19e-6	5.19e-6
		Mercury Compounds	8.11e-7	3.55e-6
		Nickel Compounds	6.55e-6	2.87e-5
08	Hatchery Boiler #3	PM	0.1	0.1
		Formaldehyde	2.34e-4	1.02e-3
		Hexane	5.62e-3	0.03
		POM	3.94e-6	1.72e-5
		Arsenic Compounds	6.24e-7	2.73e-6
		Beryllium Compounds	3.74e-8	1.64e-7
		Cadmium Compounds	3.43e-6	1.5e-5
		Cobalt Compounds	2.62e-7	1.15e-6
		Manganese Compounds	1.19e-6	5.19e-6
		Mercury Compounds	8.11e-7	3.55e-6
		Nickel Compounds	6.55e-6	2.87e-5

49. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9.

SN	Limit	Regulatory Citation
06, 07, & 08	5%	Regulation 18 §18.501

50. The permittee shall use only natural gas as a fuel source for the hatchery boilers (SN-06, SN-07, and SN-08). [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

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SECTION V: COMPLIANCE PLAN AND SCHEDULE

Peco Foods, Inc. will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19 §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19 §19.410(B) and 40 CFR Part 52, Subpart E]
3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) calendar days after completing the testing. [Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
4. The permittee must provide:
 - a. Sampling ports adequate for applicable test methods;
 - b. Safe sampling platforms;
 - c. Safe access to sampling platforms; and
 - d. Utilities for sampling and testing equipment.

[Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19 §19.303 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

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SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated June 4, 2014.

Description	Category
There are no insignificant activities currently permitted for the facility.	

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]
2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and Regulation 26 §26.701(B)]
3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26 §26.406]
4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26 §26.701(A)(2)]
5. The permittee must maintain the following records of monitoring information as required by this permit.
 - a. The date, place as defined in this permit, and time of sampling or measurements;
 - b. The date(s) analyses performed;
 - c. The company or entity performing the analyses;
 - d. The analytical techniques or methods used;
 - e. The results of such analyses; and
 - f. The operating conditions existing at the time of sampling or measurement.

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

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6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26 §26.701(C)(2)(b)]
7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. The first report due after issuance of the initial Title V permit shall contain six months of data and each report thereafter shall contain 12 months of data. The report shall contain data for all monitoring requirements in effect during the reporting period. If a monitoring requirement is not in effect for the entire reporting period, only those months of data in which the monitoring requirement was in effect are required to be reported. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below:

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

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

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.
 - a. For all upset conditions (as defined in Regulation 19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:
 - i. The facility name and location;
 - ii. The process unit or emission source deviating from the permit limit;
 - iii. The permit limit, including the identification of pollutants, from which deviation occurs;
 - iv. The date and time the deviation started;
 - v. The duration of the deviation;
 - vi. The average emissions during the deviation;
 - vii. The probable cause of such deviations;

- viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
- ix. The name of the person submitting the report.

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

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

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

- 9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26 §26.701(E), and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
- 10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26 §26.701(F)(1)]
- 11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26 §26.701(F)(2)]
- 12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26 §26.701(F)(3)]

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13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26 §26.701(F)(4)]
14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26 §26.701(F)(5)]
15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26 §26.701(G)]
16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26 §26.701(H)]
17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26 §26.701(I)(1)]
18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26 §26.702(A) and (B)]
19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26 §26.703(A)]
20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26 §26.703(B)]
 - a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
 - b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;

- c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
 - d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

- 21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually. If the permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26 §26.703(E)(3)]
 - a. The identification of each term or condition of the permit that is the basis of the certification;
 - b. The compliance status;
 - c. Whether compliance was continuous or intermittent;
 - d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
 - e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

- 22. Nothing in this permit will alter or affect the following: [Regulation 26 §26.704(C)]
 - a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
 - b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
 - c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act; or
 - d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

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

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

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

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

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

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

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

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

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

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

Appendix A

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

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 hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), 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 SO₂ 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 SO₂ 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 SO₂ emission rate, in percent;

%R_g = SO₂ removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

%R_f = SO₂ 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 SO₂ inlet rate (E_{ai,o}) using the following formula:

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

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 SO₂ 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:

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

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/tn/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 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

40 CFR Part 60, Subpart JJJJJ—*National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources*

Subpart JJJJJJ—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), unless such units do not combust hazardous waste and combust comparable fuels.

(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) covered by subpart UUUUU of this part.

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

§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 (j) 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 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 PM emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce particulate matter (PM) or sulfur dioxide emissions, 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 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.

(f) 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.

(g) 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.

(h) 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).

(i) 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 (i)(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).

(j) For existing affected boilers that have not operated 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 (j)(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 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.

(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]

§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.

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

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 §63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a 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 §63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a 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 is an accurate depiction of your facility.

(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]

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 British thermal units 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 (d) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test.

(b) 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 but must continue to comply with all applicable operating limits and monitoring requirements. If your initial performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests as specified in paragraph (a) of this section.

(c) 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 (c)(1) and (2) 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) 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 but must continue to comply with all applicable operating limits and monitoring requirements.

(2) When demonstrating initial 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.

(d) For existing affected boilers that have not operated 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.

[78 FR 7508, Feb. 1, 2013]

§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 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.

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

§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 to 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.

§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.

(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]

§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 must conduct a performance stack test. 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 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 also keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used.

(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 (defined in §63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation test as defined in §63.2, you must submit relative accuracy test audit (RATA) data to EPA's CDX by using CEDRI in accordance with paragraph (e)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions 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 subpart JJJJJJ, in the boiler becoming subject to subpart JJJJJJ, or in the boiler switching out of subpart JJJJJJ due to a change to 100 percent natural gas, or you have taken a permit limit that resulted in you being subject to subpart JJJJJJ, 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]

§63.11226 Affirmative defense for violation of emission standards during malfunction.

In response to an action to enforce the standards set forth in §63.11201 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

[78 FR 7513, Feb. 1, 2013]

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.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

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 and process heaters 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.

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 periodic testing on liquid fuel. Periodic testing of 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 average 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, and comparable fuels as defined under 40 CFR 261.38.

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).

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 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 C_3H_8 .

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. 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.

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 cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired 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 either the first-ever firing of fuel in a boiler for the purpose of supplying steam or heat 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 steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose.

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).

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 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.stadards.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 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 (CARB) and Texas (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]

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
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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.
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	a. Mercury b. CO	2.2E-05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen.

[78 FR 7517, Feb. 1, 2013]

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	Conduct an initial tune-up as specified in §63.11214, and conduct a

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	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 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.
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 biennial tune-up	Conduct a tune-up of the boiler every 5 years as specified in §63.11223.
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	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 operates under an

	energy management program compatible with ISO 50001 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:
	(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.

[78 FR 7518, Feb. 1, 2013]

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	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR 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.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR 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.
3. Wet scrubber control	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.
4. Dry sorbent or activated carbon injection control	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).

5. Any other add-on air pollution control type.	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).
6. Fuel analysis	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.
7. Performance stack testing	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.
8. Oxygen analyzer system	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).

[78 FR 7519, Feb. 1, 2013]

Table 4 to Subpart JJJJJ 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	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.
	c. 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
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	e. Measure the particulate matter emission concentration	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.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.
2. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.

	c. 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
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B in appendix A-8 to part 60 of this 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.

^aIncorporated 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 samples	EPA SW-846-3050B ^a (for solid samples) or EPA SW-846-3020A ^a (for liquid samples) or ASTM D2013/D2013M ^a (for 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	

^aIncorporated 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.
	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	(a) You must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests;
				(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.
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	Data from the sorbent or activated carbon injection rate monitors and the mercury performance stack	(a) You must collect sorbent or activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests;

		§63.11211(b)	tests	
				(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.
				(c) When your unit operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. CO	Oxygen	Establish a unit-specific limit for minimum oxygen level	Data from the oxygen analyzer system specified in §63.11224(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests;
				(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.
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)	(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.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(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.

[78 FR 7520, Feb. 1, 2013]

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
	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	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	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	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	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
	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	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	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
§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. <i>See</i> §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. <i>See</i> §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). <i>See</i> §63.11225.
§63.10(a) and (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§63.10(b)(2)(i)	Recordkeeping of occurrence	No.

	and duration of startups or shutdowns	
§63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. <i>See</i> §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. <i>See</i> §63.11225 for malfunction recordkeeping requirements.
§63.10(c)(11)	Recording corrective actions	No. <i>See</i> §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. <i>See</i> §63.11225 for malfunction reporting requirements.
§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

40 CFR Part 60, Subpart III—*Standards of Performance for Stationary Compression Ignition
Internal Combustion Engines*

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

SOURCE: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) 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 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart.

Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for

engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

Emission Standards for Manufacturers

§60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this

section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

Emission Standards for Owners and Operators

§60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

Fuel Requirements for Owners and Operators

§60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

Other Requirements for Owners and Operators

§60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Compliance Requirements

§60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until

inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power.

The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_x and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_x and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

Testing Requirements for Owners and Operators

§60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the

same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \quad (\text{Eq. 1})$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (\text{Eq. 2})$$

Where:

C_i = concentration of NO_x or PM at the control device inlet,

C_o = concentration of NO_x or PM at the control device outlet, and

R = percent reduction of NO_x or PM emissions.

(2) You must normalize the NO_x or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{\text{adj}} = C_d \frac{5.9}{20.9 - \% \text{O}_2} \quad (\text{Eq. 3})$$

Where:

C_{adj} = Calculated NO_x or PM concentration adjusted to 15 percent O_2 .

C_d = Measured concentration of NO_x or PM, uncorrected.

5.9 = 20.9 percent O_2 - 15 percent O_2 , the defined O_2 correction value, percent.

$\% \text{O}_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \quad (\text{Eq. 4})$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2 , percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($\text{dscf}/106 \text{ Btu}$).

F_c = Ratio of the volume of CO₂ produced to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/106 Btu).

(ii) Calculate the CO₂ correction factor for correcting measurement data to 15 percent O₂, as follows:

$$X_{CO_2} = \frac{5.9}{F_c} \quad (\text{Eq. 5})$$

Where:

X_{CO_2} = CO₂ correction factor, percent.

5.9 = 20.9 percent O₂–15 percent O₂, the defined O₂ correction value, percent.

(iii) Calculate the NO_x and PM gas concentrations adjusted to 15 percent O₂ using CO₂ as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \quad (\text{Eq. 6})$$

Where:

C_{adj} = Calculated NO_x or PM concentration adjusted to 15 percent O₂.

C_d = Measured concentration of NO_x or PM, uncorrected.

%CO₂ = Measured CO₂ concentration, dry basis, percent.

(e) To determine compliance with the NO_x mass per unit output emission limitation, convert the concentration of NO_x in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{KW\text{-hour}} \quad (\text{Eq. 7})$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_x concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_x to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{KW\text{-hour}} \quad (\text{Eq 8})$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

Notification, Reports, and Records for Owners and Operators

§60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in 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 report must be submitted to the Administrator at the appropriate address listed in §60.4.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013]

Special Requirements

§60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in §60.4202 and §60.4205, and not those for non-emergency engines in §60.4201 and §60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards,

must meet the applicable requirements for PM in §60.4201 and §60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

§60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

General Provisions

§60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§60.4219 What definitions apply to this subpart?

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

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion

turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4211(f)(2)(ii) or (iii) and §60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart III.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013]

Table 1 to Subpart III of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO _x	HC	NO _x	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO _x + NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines

	according to §60.4202(d) ¹
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

¹Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 kW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO _x	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ ¹	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ ¹	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+ ²	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ ³	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ ³	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

¹For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

²For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

³In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed ¹	Torque (percent) ²	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

¹Engine speed: ±2 percent of point.

²Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal	a. Reduce NO _x emissions by 90	i. Select the sampling port location and		(a) For NO _x , O ₂ , and moisture measurement, ducts ≤6 inches in

combustion engine with a displacement of ≥ 30 liters per cylinder	percent or more;	number/location of traverse points at the inlet and outlet of the control device;		diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤ 12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O ₂ at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O ₂ concentration must be made at the same time as the measurements for NO _x concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO _x concentration.
		iv. Measure NO _x at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO _x concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO _x in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO _x , O ₂ , and moisture measurement, ducts ≤ 6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤ 12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point

				long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O ₂ concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O ₂ concentration must be made at the same time as the measurement for NO _x concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO _x concentration.
		iv. Measure NO _x at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, Appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO _x concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O ₂ at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O ₂ concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.

		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O ₂ concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O ₂ concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A-3.	(d) PM concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).

§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥ 30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥ 30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

CERTIFICATE OF SERVICE

I, Cynthia Hook , hereby certify that a copy of this permit has been mailed by first class mail to Peco Foods, Inc., P. O. Box 1760, Tuscaloosa, AL, 35403, on this 17th day of December _____, 2014.



Cynthia Hook , ASIII, Air Division