DIVISION OF ENVIRONMENTAL QUALITY

DRAFT OPERATING AIR PERMIT

PERMIT NUMBER: 0263-AOP-R18

IS ISSUED TO:
Entergy Arkansas, LLC - White Bluff Plant
1100 White Bluff Road
Redfield, AR 72132
Jefferson County
AFIN: 35-00110

PURSUANT TO THE RULES OF THE ARKANSAS OPERATING AIR PERMIT PROGRAM, 8 CAR PT. 42: 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:

April 13, 2023 AND April 12, 2028

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

Signed:

Demetria Kimbrough
Deputy Director, Office of Air Quality

Date

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List of Acronyms and Abbreviations

Ark. Code Ann.	Arkansas Code Annotated
AFIN	Arkansas DEQ Facility Identification Number
CAR	Code of Arkansas Rules
C.F.R.	Code of Federal Regulations
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
HAP	Hazardous Air Pollutant
Hp	Horsepower
lb/hr	Pound Per Hour
NESHAP	National Emission Standards (for) Hazardous Air Pollutants
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate Matter Equal To Or Smaller Than Ten Microns
$PM_{2.5}$	Particulate Matter Equal To Or Smaller Than 2.5 Microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	Entergy Arkansas, LLC - White Bluff Plant
AFIN:	35-00110
PERMIT NUMBER:	0263-AOP-R18
FACILITY ADDRESS:	1100 White Bluff Road Redfield, AR 72132
MAILING ADDRESS:	1100 White Bluff Road Redfield, AR 72132
COUNTY:	Jefferson County
CONTACT NAME:	Robert "Eugene" Knighten
CONTACT POSITION:	General Manager
TELEPHONE NUMBER:	(501) 609-7330
REVIEWING ENGINEER:	Shawn Hutchings
UTM North South (Y):	Zone 15: 3809023.52 m
UTM East West (X):	Zone 15: 577562.11 m

SECTION II: INTRODUCTION

Summary of Permit Activity

Entergy Arkansas, LLC. - White Bluff (AFIN: 35-00110) located in Redfield, Arkansas is a two-unit electric generating station which generates electric energy for sale. This permit modification is a PSD modification to add a new combined cycle turbine, SN-26, and associated equipment, including an emergency generator (SN-27), fire pump (SN-28), equipment leaks and lube oil vents (SN-29 through 33), storage tanks, (SN-34 and 35), and a natural gas dew point heater\ (SN-36). The new plant is nominally rated to provide approximately 750 MW. Permitted emission rates increased 139.7 tpy of particulate, 30.5 tpy of SO_2, 404.7 tpy of VOC, 1201.6 tpy of CO, 228.6 tpy of NO_x, 2,518,500 tpy of GHG, 46.17 tpy of Sulfuric Acid Mist (SAM), 324.72 tpy of Ammonia, and 13.76 tpy of total HAPs.

Prevention of Significant Deterioration Analysis

The project is PSD major for PM, $PM_{2.5}$, PM_{10}, CO, NO_X, VOC, SAM, and Greenhouse Gases.

Ambient Impact Analysis

An applicant for a Prevention of Significant Deterioration (PSD) permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification. The primary purpose of the air quality analysis is to demonstrate that new emissions emitted from a major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment.

Continuous ambient monitoring data may be required unless the predicted ambient impact or the existing ambient pollutant concentrations are less than the prescribed significant monitoring value, Significant Monitoring Concentration (SMC). The results of the SMC monitoring are shown in the table below. For $PM_{2.5}$ and Ozone, the facility stated existing ambient monitors offer conservative estimates of the background $PM_{2.5}$ and O_3 concentrations for the area. Therefore, EAL proposed to utilize this monitoring data in lieu of performing pre-construction monitoring for $PM_{2.5}$ and O_3.

Pollutant	Averaging Period	Maximum Predicted Concentrations ($\mu g/m^3$)	Significant Monitoring Concentration ($\mu g/m^3$)
CO	8-Hour	1st High (of 5 Years) 92.025	575
NO_2	Annual	1st High (of 5 Years) 0.154	14
PM_{10}	24-Hour	1st High (of 5 Years) 1.538	10

PSD modeling is performed in two stages: the significance analysis and the full impact analysis. The significance analysis considers the net emissions change associated with PSD affected emissions units to determine if the increased emissions will have a significant impact upon the surrounding area. If the results of the significance analysis are below the corresponding Modeling Significance Levels, the full impact analysis is not required. The below results for the ozone SIL represent the calculated cumulative consumption of the ozone SIL. A summary of the results of the significance analysis is in the table below.

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Significance Level ($\mu g/m^3$)
CO	1-hour	592.180	2,000
	8-hour	92.025	500
PM_{10}	24-hour	1.538	5
	Annual	0.070	1.0
$PM_{2.5}$ (Increment)	24-hour	1.605	1.2
	Annual	0.082	0.13
$PM_{2.5}$ (NAAQS)	24-hour	1.098	1.2
	Annual	0.067	0.13
NO_2	1-hour	5.944	7.52
	Annual	0.154	1.0
Ozone	8-hour	0.582	1 ppb

Based on the results presented in the prior table, a full impact analysis was required only for $PM_{2.5}$ 24-hr increment. The full impact analysis modeling must show that the emissions from the facility and surrounding existing sources will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. For the $PM_{2.5}$, Tier-1 Screening of Secondary $PM_{2.5}$ impacts using MERPS was used to estimate the concentration of $PM_{2.5}$ secondary formation from NO_X and SO_2. The concentration from secondary formation was added to the modeled concentration for primary $PM_{2.5}$. That value is represented in the table below with the concentrations for other pollutants.

Pollutant	Averaging Period	Maximum Predicted Increment Consumption ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	Percent of Class II Increment (%)
$PM_{2.5}$	24-hour	2.215	9	24.6

Arkansas 8 CAR pt. 41 requires that if the issuance of a permit for any major stationary source or any major modification would result in the consumption of more than fifty percent of the available annual increment or eighty percent of any short term increment, the person applying for such a permit shall submit to the Division an assessment of the effects that the proposed consumption would have upon the industrial and economic development within the area of the proposed source and the alternatives to such consumption including alternate siting of the proposed source.

As the results of the cumulative impact analysis was below 50% of the increment it is mathematically impossible for the facility to have consumed more than 50% of the available annual increment or 80% of any short term increment. No analysis was needed.

Additional Impact Review

An applicant for a Prevention of Significant Deterioration (PSD) permit must prepare additional impact analyses for each pollutant subject to the regulation under the Clean Air Act Amendments. Three areas constitute the Additional Impact Review: a growth analysis, a soils and vegetation analysis, and a visibility analysis.

Growth Analysis

The Growth Analysis estimates the impact of atmospheric emissions that will be generated by the projected growth from industrial, commercial, and residential growth associated with the project.

The growth impacts analysis evaluates a project's potential impact on industrial, commercial, and residential growth in the surrounding area. The JPS project is expected to have minimal impacts on industrial, commercial, and residential growth in the surrounding area.

Soils and Vegetation Analysis

A PSD applicant must also conduct a soil and vegetation air pollution impact analysis based on an inventory of the soils and vegetation types found in the impact area. The soils and vegetation impacts analysis is required to evaluate a project's potential adverse impacts on soil and vegetation in the surrounding area. The JPS project is not expected to have any adverse impacts on soil and vegetation in the surrounding area.

Visibility Analysis

As part of PSD review a facility must look at the visibility impacts of the project. In support of the application the facility submitted the following:

> *The proposed project will comply with all regulatory requirements for opacity. EAL has extensive experience operating natural gas-fired combustion turbine EGUs at numerous locations. Because low-sulfur pipeline-quality natural gas is such a clean burning fuel, to the best of EAL's knowledge there has never been a circumstance where operation of such an EGU has caused visibility impairment at any on-site or off-site receptor or area. This statement is true for routine operations as well as maintenance, startup, and shutdown operations of EAL's combustion turbine EGUs. The emissions of visibility impairing pollutants, including sulfates, NOx, and PM/soot are very low because (1) clean burning low-sulfur pipeline quality gas will be fired and (2) state-of-the art emission controls will be employed. Based on EAL's extensive experience operating natural gas-fired combustion turbine EGUs, EAL is confident in asserting that the JPS EGU will not cause or contribute to visibility impairment at any Class I or Class II off-site receptor or area, including all nearby airports, state forests, parks, scenic vistas, areas of special historic interest, or any other sensitive areas. Based on this information, EAL has concluded that no further visibility analysis is required.*

Class I Impacts

As part of a PSD application a facility is required to conduct an analysis of the ambient impacts on Class I areas. The two closest Class one areas are Upper Buffalo Wilderness Class I Area 200km to the northwest and Caney Creek Wilderness Class I Area 178 km to the west. The facility submitted AERMOD modeling which showed the impacts at 50km to demonstrate Class I impacts were not an issue. This analysis states that impacts on the Class I areas should be less than the impacts at the 50km range as the Class I areas are at least three times further distant. A summary of the results of the significance analysis is in the table below. The modeled concentrations were all below the Significance Level and further modeling for these pollutants was not required.

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Class I Significance Level ($\mu g/m^3$)
PM_{10}	24-hour	0.077	0.3
	Annual	0.00513	0.2
$PM_{2.5}$	24-hour	0.141	0.27
	Annual	0.0164	0.03
NO_2	Annual	0.008	0.1

Best Available Control Technology

The PSD regulations mandate that a case-by-case Best Available Control Technology (BACT) analysis be performed on all new or modified affected sources at which a net emissions increase will occur. The following table is a summary of the BACT determinations made in this permit.

For more detailed discussion of BACT see the BACT analysis section of the permit application. The following summarizes the BACT analysis.

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-26	Combined Cycle Turbine	NO_X	Dry Low-NO_x Combustors and Selective Catalytic Reduction (SCR)	2.0 ppmvd @ 15% O_2 (3-hr avg) excluding startup, shutdown, and tuning 40.60 lb/hr during startup, shutdown, and tuning
		CO	Good Combustion Practices and Catalytic Oxidation	2.0 ppmvd @ 15% O_2 (3-hr avg) excluding startup, shutdown, and tuning 24.72 lb/hr during startup, shutdown, and tuning
		VOC	Good Combustion Practices and Catalytic Oxidation	1.5 ppmvd @ 15% O_2 (3-hr avg) excluding startup, shutdown, and tuning 10.62 lb/hr during startup, shutdown, and tuning
		PM /PM_{10} / $PM_{2.5}$ / Opacity	Low Sulfur Pipeline Natural Gas, Good Combustion Practices	0.0097 lb/MMBtu (3-hr avg) Opacity 5%
		SAM	Low Sulfur Pipeline Natural Gas	0.5 gr S/100 scf 21.38 lb/hr 46.17 TPY

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG	High-Efficiency Combined Cycle System, Low-Carbon Natural Gas Fuel	800 lb CO_2e/MWh gross (12-mo avg) prior to Jan 1, 2032 100 lb CO_2e/MWh gross (12-mo avg) after December 2031
SN-27	Emergency Standby Generator	NO_X	Tier 2 USEPA-Certified NSPS Subpart IIII Engine, Good Combustion Practices	6.4 g/kWh
		CO	Tier 2 USEPA-Certified NSPS Subpart IIII Engine	3.5 g/kWh
		VOC	Tier 2 USEPA-Certified Engine, Manufacturer's Guarantee	0.56 g/kWh
		PM /PM_{10} / $PM_{2.5}$ / Opacity	Tier 2 USEPA-Certified NSPS Subpart IIII Engine	0.20 g/kWh Opacity 5%
		GHG	Efficient Tier 2 USEPA-Certified Engine, Good Combustion Practices	163 lb/MMBTU
SN-28	Emergency Diesel Fire Water Pump	NO_X	Tier 3 USEPA-Certified NSPS Subpart IIII Engine, Good Combustion Practices	4.0 g/kWh
		CO	Tier 3 USEPA-Certified NSPS Subpart IIII Engine	3.5 g/kWh
		VOC	Tier 3 USEPA-Certified Engine, Manufacturer's Guarantee	0.11 g/kWh
		PM /PM_{10} / $PM_{2.5}$ / Opacity	Tier 3 USEPA-Certified NSPS Subpart IIII Engine	0.20 g/kWh Opacity 5%
		GHG	Efficient Tier 3 USEPA-Certified Engine, Good Combustion Practices	163 lb/MMBTU
SN-29	Natural Gas Leaks	VOC	Audio-Visual-Olfactory (AVO) LDAR Program	0.1 lb/hr, 0.4 tpy
		GHG (CH_4)	Audio-Visual-Olfactory (AVO) LDAR Program	400 tpy CO_2e

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-31	Diesel Leaks	VOC	Audio-Visual-Olfactory (AVO) LDAR Program	0.1 lb/hr, 0.1 tpy
SN-32	Combustion Turbine Lube Oil Vent	VOC	Mist Eliminator	0.1 lb/hr, 0.1 tpy
		PM /PM_{10} / $PM_{2.5}$ / Opacity	Mist Eliminator	0.1 lb/hr, 0.1 tpy Opacity 5%
SN-33	Steam Turbine Lube Oil Vent	VOC	Mist Eliminator	0.1 lb/hr, 0.1 tpy
		PM_{10} / $PM_{2.5}$	Mist Eliminator	0.1 lb/hr, 0.1 tpy
SN-34	Natural Gas Condensate Tank 1	VOC	White Fixed-Roof Tank, Submerged Fill Pipe, Atmospheric Vent, Good Operating Practices	3.5 lb/hr, 0.1 tpy
SN-35	Natural Gas Condensate Tank 2	VOC	White Fixed-Roof Tank, Submerged Fill Pipe, Atmospheric Vent, Good Operating Practices	3.5 lb/hr, 0.1 tpy
SN-36	Natural Gas Dewpoint Heater	NO_X	Ultra-Low NO_x Burners	0.011 lb/MMBtu
		CO	Good Combustion Practices	0.037 lb/MMBtu
		VOC	Good Combustion Practices	0.008 lb/MMBtu
		PM /PM_{10} / $PM_{2.5}$ / Opacity	Low Sulfur Pipeline Natural Gas, Good Combustion Practices	0.0048 lb/MMBtu Opacity 5%
		GHG	Clean-Burning Efficient Pipeline Natural Gas, Good Combustion Practices	121 lb CO_2e/MMBTU

Process Description

White Bluff Steam Electric Station operates two identical coal-fired units (Units 1 and 2) with a total nominal capacity of approximately 1690 megawatts (MW). Sub-bituminous or bituminous coal is delivered by rail or barge. Each rail car is equipped with rotary couplings which enable the rotary car dumper (SN-03) to grasp one car at a time and empty it without removing the car from the train. The rotary car dumper is capable of emptying approximately 30 cars per hour. Transfer conveyors move the coal to a transfer tower. From here the coal can be conveyed to three different areas including the plant to be pulverized and burned, the stacker/reclaimer, or the storage area. The stacker reclaimer has the capability of either stacking coal out or reclaiming

the coal from the storage area. The storage area is used for long term storage of coal and is also managed by the use of heavy vehicles including front end loaders and bull dozers.

Coal is burned in the steam generators (SN-01 and SN-02) which feed turbine generators to produce electricity. Exhaust gases from both units are expelled through two 1,000 foot stacks within a common outer chimney shell. Waste heat dissipation is through two hyperbolic natural draft cooling towers (SN-17 and SN-18) which obtain makeup water from the Arkansas River and from the capture of site drainage. Other major plant components include facilities for storage and handling of coal and disposal of ash; a switch-yard; electrostatic precipitators; water treatment; surge and other ponds; and intake and discharge structures.

The White Bluff Facility also has a nominal 750 MW turbine. This turbine is a natural gas-fired combined cycle turbine equipped with supplementary-fired duct burners and a Heat Recovery Steam Generator (HRSG). In addition to power from a generator turned by the gas turbine shaft, additional power is supplied by a generator turned by a steam turbine which is fed steam generated in the HRSG. Final condensation of steam exiting the steam turbine is accomplished using air-cooled condensers.

The turbine facility will have other ancillary sources of air pollution. This includes but is not limited to emissions from a natural gas-fired dewpoint heater to heat the natural gas fuel fed to the gas turbines and duct burners, diesel-fired internal combustion (IC) engines in support of emergency standby power generation and emergency fire pump operations, diesel storage tanks, natural gas condensate storage tanks, lube oil system vents, and diesel, natural gas and ammonia leak emissions

Rules and Regulations

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

Rules and Regulations
Arkansas Air Pollution Control Code, 8 CAR pt. 40, effective March 14, 2016
Rules of the Arkansas Plan of Implementation for Air Pollution Control, 8 CAR pt. 41, effective May 6, 2022
Rules of the Arkansas Operating Air Permit Program, 8 CAR pt. 42, effective March 14, 2016
40 C.F.R. § 52.21 *Prevention of significant deterioration of air quality*
40 C.F.R. § 52.173 *Visibility protection*
40 C.F.R. § 60, Subpart D – *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*
40 C.F.R. § 61, Subpart M – *National Emissions Standard for Asbestos*

Rules and Regulations
40 C.F.R. § 72, Subpart A-D – Permits Regulation (Acid Rain)
40 C.F.R. § 73, Subpart B – Sulfur Dioxide Allowance System
40 C.F.R. § 75 – Continuous Emission Monitoring
40 C.F.R. § 76 – Acid Rain Nitrogen Oxide Emission Reduction Program
40 C.F.R. § 77 – Excess Emissions
40 C.F.R. § 64 – Compliance Assurance Monitoring
40 C.F.R. § 82 – Protection of Stratospheric Ozone
40 C.F.R. § 63 Subpart ZZZZ - *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*
40 C.F.R. § 60, Subpart IIII - *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
40 C.F.R. § 60, Subpart KKKKa - *Standards of Performance for Stationary Combustion Turbines*
40 C.F.R. § 60, Subpart TTTTa - *Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units*
40 C.F.R. § 63, Subpart UUUUU – *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* (MATS)
40 C.F.R. § 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*
40 C.F.R. § 97, Subpart BBBBB – *CSAPR NOx Ozone Season Group 1 Trading Program*

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	911.8	3543.9
		PM_{10}	1,537.0	6559.6
		$PM_{2.5}$	49.8	139.7
		SO_2	20,994.6	46,180.3
		VOC	2,660.2	738.5
		CO	10,227.5	13,068
		NO_X	12,569.6	53,750.4
		Lead	0.61	2.01
		CO_2e	-	2,518,500
HAPs		SAM	43.08	122.17
		Cyanide	2.7	11.5
		Hydrogen Chloride	86.62	184.89
		Hydrogen Fluoride	157.5	690
		Methylene Chloride	0.32	1.34
		Total HAPs***	261.49	951.75
Air Contaminants ***		Ammonia	75.26	324.72
01 (C1)	Unit 1 Boiler – Coal Fired	PM	346.9	1519.6
		PM_{10}	714.0	3,127.4
		SO_2	10,440.0	22,863.6
		VOC	35.0	153.3
		CO	1,342.5	5,880.2
		NO_x	6,090.0	26,674.2
		Lead	0.3	1.0
		SAM	10.1	22.1
		Cyanide	1.35	5.75
		Hydrogen Chloride	43.20	92.00
		Hydrogen Fluoride	78.75	345.00
		Methylene Chloride	0.16	0.67
		Total HAPs	126.91	20.7
01 (C2)	Unit 1 Boiler – No. 2 Fuel Oil or Bio-diesel	PM	14.6	64.0
		PM_{10}	24.1	105.6
		SO_2	518.3	2270.0
		VOC	1.9	8.1
		CO	36.5	159.9
		NOx	175.2	767.4
		Lead	0.01	0.04
		SAM	8.0	34.8
		Total Other HAPs	0.48	2.07

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			Lb/hr	tpy
02 (C1)	Unit 2 Boiler – Coal Fired	PM	346.9	1519.6
		PM_{10}	714.0	3,127.4
		SO_2	10,440.0	22,863.6
		VOC	35.0	153.3
		CO	1,342.5	5,880.2
		NO_x	6,090.0	26,674.2
		Lead	0.3	1.0
		SAM	10.1	22.1
		Cyanide	1.35	5.75
		Hydrogen Chloride	43.20	92.00
		Hydrogen Fluoride	78.75	345.00
		Methylene Chloride	0.16	0.67
		Total Other HAPs	4.8	20.7
02 (C2)	Unit 2 Boiler – No. 2 Fuel Oil or Bio-diesel	PM	14.6	64.0
		PM_{10}	24.1	105.6
		SO_2	518.3	2270.0
		VOC	1.9	8.1
		CO	36.5	159.9
		NOx	175.2	767.4
		Lead	0.01	0.04
		SAM	8.0	34.8
		Total Other HAPs	0.48	2.07
03	Rail Car Rotary Dumper	PM	0.1	0.1
		PM_{10}	0.1	0.1
		VOC	1.3	-
03 06A	Rail Car Rotary Dumper and Handling/ Conveying VOC Emissions	VOC	-	2.2
04 (M30-M31)	Fly Ash Silos (2) with Fabric Filters	PM	0.1	0.1
		PM_{10}	0.1	0.1
05 (C3)	Auxiliary Boiler	PM	2.7	11.8
		PM_{10}	4.5	19.4
		SO_2	95.2	416.8
		VOC	0.4	1.5
		CO	18.7	81.5
		NOx	32.2	140.9
		Lead	0.01	0.01
		SAM	1.5	6.4

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			Lb/hr	tpy
		Hydrogen Chloride	0.22	0.89
		Total Other HAPs	0.09	0.38
06A	Handling/ Conveying Emissions	PM	0.8	3.4
		PM_{10}	0.4	1.6
		VOC	0.3	-
06B	Stacker/ Reclaimer Emissions	PM	1.0	4.3
		PM_{10}	0.5	2.1
06C	Storage Piles/Haul Road Emissions	PM	143.6	280.4
		PM_{10}	41.1	95.0
		VOC	27.4	5.0
07	Fuel Oil Tank	VOC	1.7	1.9
17 (X24)	Cooling Tower	PM	4.6	19.9
		PM_{10}	4.6	19.9
18 (X25)	Cooling Tower	PM	4.6	19.9
		PM_{10}	4.6	19.9
19	Coal Barging and Transfer	PM	9.8	24.2
		PM_{10}	2.5	6.1
20	Degreasing Operations	VOC	6.8	13.6
21	Emergency Diesel Generator	PM	0.6	0.6
		PM_{10}	0.5	0.6
		SO_2	4.2	4.5
		VOC	0.8	0.8
		CO	7.0	7.6
		NO_X	26.4	28.5
		Total HAPs	0.02	0.02
22	Emergency Diesel Fire Pump	PM	0.2	0.2
		PM_{10}	0.2	0.2
		SO_2	0.8	1.2
		VOC	1.0	1.4
		CO	2.1	3.2
		NO_X	2.5	3.7
		Total HAPs	0.02	0.02
24	Telecom Emergency Generator Engine (Propane-fired)	PM	0.1	0.1
		PM_{10}	0.1	0.1
		SO_2	0.1	0.1
		VOC	1.5	0.4
		CO	54.7	13.7
		NO_X	1.5	0.4
		Total HAPs	0.04	0.01

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			Lb/hr	tpy
25	Misc Storage Tank (Gasoline, 1000 gal)	VOC	11.7	0.4
		Total HAPs	0.67	0.02
26	Combined Cycle Turbine – Normal Operation	PM	48.4	138.9
		PM_{10}	48.4	138.9
		$PM_{2.5}$	48.4	138.9
		SO_2	14.0	30.2
		VOC	10.7	402.8
		CO	24.8	1195.9
		NO_x	40.6	219.9
		SAM	21.38	46.17
		CO_2e	-	2,514,400
	Combined Cycle Turbine – Startup/Shutdown Operations	PM	48.4	
		PM_{10}	48.4	
		$PM_{2.5}$	48.4	
		SO_2	14.0	
		VOC	2527.0	
		CO	7441.0	
		NO_x	294.0	
		SAM	21.38	
		CO_2e	-	
26	Combined Cycle Turbine – All Operations	Total HAPs	3.15	13.59
		Ammonia	75.16	324.32
27	Emergency Standby Generator	PM	1.0	0.3
		PM_{10}	1.0	0.3
		$PM_{2.5}$	1.0	0.3
		SO_2	0.1	0.1
		VOC	2.7	0.7
		CO	16.9	4.3
		NO_x	30.8	7.7
		CO_2e	-	1,000
		Total HAPs	0.04	0.01
28	Emergency Diesel Fire Water Pump	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	1.9	0.5
		NO_x	2.1	0.6
		CO_2e	-	100

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			Lb/hr	tpy
		Total HAPs	0.01	0.01
29	Natural Gas Leaks	VOC	0.1	0.4
		CO_2e	-	400
		Total HAPs	0.02	0.09
30	Ammonia Leaks	Ammonia	0.1	0.4
31	Diesel Leaks	VOC	0.1	0.1
		Total HAPs	0.01	0.01
32	Combustion Turbine Lube Oil Vent	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		VOC	0.1	0.1
		Total HAPs	0.01	0.01
33	Steam Turbine Lube Oil Vent	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		VOC	0.1	0.1
		Total HAPs	0.01	0.01
34	Natural Gas Condensate Tank 1	VOC	3.5	0.1
		Total HAPs	0.02	0.01
35	Natural Gas Condensate Tank 2	VOC	3.5	0.1
		Total HAPs	0.02	0.01
36	Natural Gas Dewpoint Heater	PM	0.1	0.2
		PM_{10}	0.1	0.2
		$PM_{2.5}$	0.1	0.2
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.2	0.9
		NO_x	0.1	0.3
		CO_2e	-	2,600
		Total HAPs	0.01	0.01

*$PM_{2.5}$ limits are source specific, if required. Not all sources have $PM_{2.5}$ limits.
**HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
***Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

SECTION III: PERMIT HISTORY

263-A was the first permit issued to the facility. 263-A permitted the installation of two coal-fired steam electric generating units served by a combined 1000 foot stack. The permit established the New Source Performance Standards limits for sulfur dioxide by usage of low sulfur coal.

263-AR-1 was issued to Arkansas Power & Light Company - White Bluff Steam Electric Station on April 9, 1991. After the issuance of permit 263-A, it was discovered that the particulate emission limitation was 0.027 lb/MMBtu heat input instead of the 40 C.F.R. 60 Subpart D limit of 0.10 lb/MMBtu heat input. The more stringent limitation caused a problem with compliance with the operating permit. Due to the variability in the quality of coal, AP&L requested a revised particulate emission limit in order to maintain compliance with its operating permit. Air permit 263-AR-1 incorporated the new limits for particulate matter, identified source of pollution not previously addressed in the original permit, and estimated pollution emissions from fuel oil storage facilities and air toxic emissions.

263-AOP-R0 was the first operating air permit issued to Entergy-Arkansas, Inc. - White Bluff Steam Electric Station under Regulation 26. No physical changes in the method of operation at the facility occurred prompting this permit issuance.

> Entergy-Arkansas, Inc. proposed to increase the CO limit for the White Bluff facility from 300 lb/hr (50 ppm) to 3247.0 lb/hr or 300 ppm hourly (100 ppm 24-hour average) to reflect actual emissions indicated by stack testing. This increase in CO emissions was not subject to PSD review, because previous permit limits were based on AP-42 factors that were inaccurate for this facility. Also, the White Bluff Steam Electric Station began construction before the PSD regulations were promulgated. Modeling analysis at a 500 ppm emission rate was conducted and showed no significant impact to the *NAAQS*.
>
> Entergy-Arkansas, Inc. elected to take on a new NO_X emission limit of 0.45 lb/MMBtu annual average at White Bluff Units 1 and 2. This early election was allowed under 40 C.F.R. 76 of the Acid Rain Regulations. The NSPS limit of 0.7 lb/MMBtu and the state-imposed lb/hr limit still apply to these units.

263-AOP-R1 was issued on May 30, 2000. The facility modified the Title V permit to allow for the receipt of coal via barge. Barges arrived at the plant on the Arkansas River. The coal was transferred from the barge to trucks through a series of conveyors and hoppers (SN-19). This modification also moved the following sources to the insignificant activities list: SN-08, SN-09, SN-10, SN-11, SN-12, and SN-13.

263-AOP-R2 was issued on December 20, 2002. This minor modification was necessary to replace the control equipment associated with the Rail Car Rotary Dumper (SN-03) and Handling/Conveying Emissions (SN-06) with non-hazardous dust suppressant chemical foam spraying stations. The volatile organic compound (VOC) emissions from the dust suppressant

chemical foam spray were permitted at 17.7 tons per year. This permitting action also modified the visible emissions conditions for SN-06. In addition, the following sources no longer operate or never existed at the facility and were removed from the permit: Barge Unloading Operations (SN-19) and some of the Handling/Conveying Emissions (SN-06) M10 Emergency Stackout Pile, M12 Dead Storage Hopper 4A, M13 Dead Storage Hopper 3A, M14 Dead Storage Hopper 2A, and M33 Fly Ash Rail Car Loading Silo. The M15 Dead Storage Vault was removed from the permit as a source of emissions since it is completely enclosed, underground, and the rotoclone dust collector connected to it is inoperable. This rotoclone was removed or abandoned in place.

263-AOP-R3 was issued on April 28, 2005. In addition to renewing the facility's Title V air permit, this permitting action was necessary to permit emissions of hazardous air pollutants (HAPs); recalculate the permitted coal handling emission rates (SN-06); increase the throughput of SN-14 and SN-16; update the PM and PM_{10} emission rates (SN-01, SN-02, and SN-05) to include condensable particulate matter; update the insignificant activities list; add new stack testing requirements for PM, PM_{10}, and CO; permit the degreasers (SN-20) which were previously submitted as insignificant; correct the fly ash silos (SN-04) permitted PM emission rates; correct the facility name to Entergy Arkansas, Inc. from Entergy Services, Inc.; remove emission point M32 (SN-06A) since this emission point has been removed from service; increase the cooling tower circulating water flow rates (SN-17 and SN-18); and reduce the permitted VOC content of the chemical foam spray used at SN-03 and SN-06A. The total permitted emission rate increases due to this permitting action included: 1,013.6 tons per year (tpy) PM, 738.7 tpy PM_{10}, 39.2 tpy SO_2, and all hazardous air pollutant and air contaminant emission rates for this facility increased due to these pollutants previously not being permitted.

263-AOP-R4 was issued on April 26, 2006. Entergy Arkansas, Inc. - White Bluff located in Redfield, Arkansas is a two-unit electric generating station which generates electric energy for sale. This permitting action was necessary to:

1. Permit coal barging and transfer (SN-19);
2. Increase the permitted circulating water flow rate to 22,125 kgal/hr for the cooling towers (SN-17 and SN-18);
3. Reduce the permitted TDS (total dissolved solids) limit to 2,800 parts per million for the cooling towers (SN-17 and SN-18);
4. Remove the words "from northeastern Wyoming" from the process description;
5. Remove the "-88" from ASTM D4507-88 in Specific Condition # 29;
6. Add 40 C.F.R. § 63 Subpart DDDDD - *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* as applicable to SN-05;
7. Allow for the use of bituminous coal;
8. Increase the coal sulfur and ash contents;
9. Set the PM_{10} emission rate limits equal to the PM emission rate limits for SN-01 and SN-02;
10. Revise Specific Condition # 25; and
11. Add Specific Condition # 26.

The total annual permitted emission rate increases due to this permitting action include: 2,311.3 tons per year (tpy) PM and 5,034.8 tpy PM_{10}. These increases do not require PSD review because there is no physical modification to the boilers (SN-01 and SN-02) and the coal barging and transfer (SN-19) has been permitted below the PSD trigger.

0263-AOP-R5 was issued on August 24, 2007. With the modification, Entergy requested to remove the requirement to use dust suppressant foam at SN-06A. Entergy completed a project improving the conveyor enclosure seals, installed new seals, and added a dust collector. This dust collector or "Bin-vent" is vented inside the building. Entergy also submitted the language changes necessary to incorporate bio-diesel into the permit as fuel for SN-01 or SN-02. Entergy also submitted the necessary calculations to incorporate their sulfuric acid (H_2SO_4) emissions from SN-01 and SN-02. Additionally, Entergy determined that Scenario 2 – Fuel Oil Firing, PM/PM_{10} emissions from SN-01 and SN-02 is more accurate when the control efficiency for the ESP is removed since the ESP is not in operation during startup when fuel oil is being used. Revised emissions reflecting this determination were submitted. The total annual permitted emission rate increases due to this permitting action include: 12.3 tons per year PM, 12.7 tpy PM_{10}, and 178.52 tpy H_2SO_4. Additionally, on July 30, 2007, the District of Columbia Court of Appeal vacated the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT). Due to the Boiler MACT rules being vacated, the permit was updated by removing all conditions and wording related to the Boiler MACT.

0263-AOP-R6 was issued on January 12, 2009. Entergy was authorized to install a new dust suppression system at the bottom of 2A conveyor (SN-06A), and revised the fuel oil N_2O emissions based on updated emission factors. The N_2O annual emissions for the fuel oil fired scenario increased by 10.48 tpy. The facility total annual permitted emission rates increase was 0.88 tpy N_2O.

0263-AOP-R7 was issued on August 9, 2012. The Title V permit was renewed with modifications. The changes included adding a replacement fire pump, moving an emergency generator from the Insignificant Activity list to a permitted source, increased solvent use (SN-20) to 4000 gallons per year, added H_2SO_4 (sulfuric acid) emission estimates to auxiliary boiler emission rates, revised the oil fired scenario, and added a portable diesel tank (T127) to the insignificant activity list. Permitted emissions of particulate matter decreased due to coal handling emission calculation updates. Other pollutant emission rates changed in minor amounts due to updated calculations. Permitted emissions changed by -285.5 tpy PM, -108.5 tpy PM_{10}, 6.9 tpy SO_2, 9.2 tpy CO, 31.5 tpy NOx, -59.7 tpy H_2SO_4, 1.2 tpy HCl and less than 1 tpy change in all other HAP emission rates combined.

0263-AOP-R8 was issued on January 22, 2015. The applicable requirements of Mercury Air Toxic Standards were incorporated into the permit. Two activated carbon silos and two aqueous halide storage units including additional traffic on the roads for deliveries of those materials were permitted. Overall, permitted emission decreased by 77.5 tpy PM and 15.0 tpy PM_{10}.

0263-AOP-R9 was issued on September 25, 2015. The facility was permitted to retrofit SN-01 and SN-02 with low NO_X burners and separated overfire air. The permitted CO emission limits for SN-01 and SN-02 were decreased. PSD review was triggered for CO due to the retrofit project because the permittee determined the actual increase in CO emissions resulted in a major modification. A BACT limitation was imposed as part of the PSD review.

Sources	Pollutant	BACT Determination		
Each Coal Fired Unit (SN-01 and SN-02)	CO	Good Combustion Practices	0.15 lb/MMBtu	Bi-Annual Stack Testing (3-hour average)

An emergency engine (SN-23) not addressed in the previous permit and the applicable requirements for the Industrial Boiler MACT for SN-05 were incorporated. Permitted emission for CO due to the retrofit project decreased by 16,683.4 tpy CO. SN-23 increased permitted emissions by 0.1 tpy PM/PM_{10}, 0.1 tpy SO_2, 0.1 tpy VOC, 0.3 tpy CO, 0.4 tpy NO_X, and less than 0.01 tpy of HAP. This engine was listed as an insignificant activity in previous permits.

0263-AOP-R10 was issued on May 10, 2016. Entergy submitted an application to permit VOC emissions from use of dust suppressant on the haul roads (M34) and the landfill surfaces (M36) included in SN-06C, remove former Specific Conditions #93 and #94 because the underlying Boiler MACT provisions were vacated, and relax the compliance demonstration found in Specific Condition #173 from being performed annually to once every three years. Previously this condition did not identify which method(s) of determining flow rate could be used. The revised condition now includes dye dilution test, properly calibrated follow meters, or other equivalent flow measurement methods. Overall, permitted emissions increased by 5.0 tpy VOC.

0263-AOP-R11 was issued on November 8, 2017. This was a Title V renewal for this permit. No physical changes or changes in the method of operation were requested. This renewal included revisions to emission estimates based on updated emission factors and calculation methodologies. Additionally, the emission estimate for the emergency fire pump (SN-22) was changed to reflect the engine's actual block capacity of 365 HP instead of the 323 HP which was provided by the manufacturer previously. The facility's permitted annual emissions increased by 1.9 tpy VOC, 53.7 tpy CO, 1.1 tpy NOx. The facility's permitted annual emissions decreased by 43.8 tpy SO_2.

0263-AOP-R12 was issued on January 29, 2018. With this administrative amendment, the facility added a 17 gallon ultrasonic parts washer as an A-13 insignificant activity. This revision also updated Plantwide Condition #3 to be consistent with ADEQ's Stack Testing Guidelines.

0263-AOP-R13 was issued on September 14, 2018. With this administrative amendment, the facility replaced three existing insignificant tanks with new tanks of identical size that will continue to store the same liquid: bulk storage tank #25 and #26 (T125) and bulk storage tank #12 (T30). This revision also included the addition of two hoppers for storing powdered halide product which would provide the facility with the option of utilizing either a powdered halide or

an aqueous halide solution as part of the mercury emission control system for the two coal-fired units. The hoppers qualify as A-13 insignificant activity. Lastly, this revision removed General Provision #28.

0263-AOP-R14 was issued on December 19, 2018. With this administrative amendment, the facility added two diesel-fired glycol heaters to serve as freeze protection on the lake tank system during the winter. The heaters qualified as A-13 insignificant activity. There were no changes to the facility's permitted annual emission limits.

0263-AOP-R15 was issued on February 20, 2020. With this administrative amendment, the facility added a bottom ash bunker system. The bottom ash bunker system qualifies as A-13 insignificant activity. There were no changes to the facility's permitted annual emission limits.

0263-AOP-R16 was issued on September 30, 2020. With this modification, the facility made the following changes: removed a 4,000 gal no.2 fuel oil storage tank (SN-14), 4,000 gal gasoline storage tank (SN-16) and 20 KW propane-fired telecom emergency generator (SN-23); reclassified the 10,000 gal no.2 fuel oil storage tank (SN-15) as an A-3 insignificant activity (T26); added a new 64.1 Hp propane-fired emergency generator (SN-24), 1,000 gal gasoline storage tank (SN-25), 1,000 gal no.2 fuel oil storage tank (T132, A-3 insignificant activity); added conditions for complying with BART for SN-01, SN-02, and SN-05; and decreased the permitted annual HCl limits for SN-01 and SN-02 to 92.0 tpy each. The new HCl emission limits are based on NESHAP UUUUU HCl emission factor of 2.0E-03 lb/MMBtu instead of AP-42 HCl emission factor of 1.2 lb/ton. The facility's permitted annual emission increased by 0.7 tpy VOC and 13.4 tpy CO. The facility's permitted annual emissions decreased by 5336.00 tpy HCl and 5334.64 tpy total HAPs.

0263-AOP-R17 was issued on April 13, 2023. In this renewal the facility added the ability to operate an additional coal yard dozer, revised specific conditions with regards to applicable CO limits for SN-01 and SN-02 due to completion of a previous project to install Low NOx Burners and Separated Overfire Air, and added specific conditions requiring Unit 1 (SN-01) and Unit 2 (SN-02) each meet a SO_2 emission limit of 0.6 lb/MMBtu based on a 30-boiler-operating day rolling average and that each unit to cease firing coal by December 31, 2028. Permitted emission rates increased 5 tpy of PM_{10} and 0.89 tpy of HCl. All other pollutants permitted rates remained the same or decreased.

The permittee requested revisions of Specific Condition 7 to clearly define the reporting obligations for excess emissions caused by startups, shutdowns, and malfunctions in relation to NSPS Subpart D. That condition of the permit does not cite NSPS Subpart D as its basis. Specific Condition 7 stands to show compliance with the facility's Title V limits outside of the requirements of NSPS Subpart D. The changes were not made.

SECTION IV: SPECIFIC CONDITIONS

SN-01, SN-02, and SN-05
Boilers

Source Description

SN-01 and SN-02 are 8700 million BTU per hour coal fired boilers. The boilers use sub-bituminous or bituminous coal as their primary fuel and No. 2 fuel oil or bio-diesel as the start-up fuel at a maximum rate of 1000 MMBtu/hr. The boilers are permitted to operate under alternating scenarios. Scenario I represents combustion from coal and Scenario II represents No. 2 fuel oil or bio-diesel combustion. At times when coal and oil are fired together, and for one hour after switching from scenario I to Scenario II, the limits of Scenario I apply. The boilers supply steam which feed turbine generators to produce electricity. Both units are subject to NSPS Subpart D, which regulates emissions of particulate matter, sulfur dioxide and nitrogen oxides from fossil fuel-fired steam generators.

Particulate emissions from these two units are controlled with electrostatic precipitators. NSPS emissions standards for particulate matter are 0.1 lb/MMBtu and a maximum opacity of 20 percent. A continuous opacity monitor records emissions opacity.

Sulfur dioxide emissions from SN-01 and SN-02 are limited by the use of low-sulfur coal. The NSPS emission standard for sulfur dioxide is 1.2 lb/MMBtu. The BART sulfur dioxide emission limit for these units is 0.60 lb/MMBtu. A continuous emissions monitor measures sulfur dioxide emissions.

SN-05 is a 183 million BTU per hour boiler. This auxiliary boiler combusts No. 2 fuel oil or bio-diesel in order to provide steam for unit start-up activities. There are no control devices associated with this source.

Specific Conditions

1. The permittee shall not exceed the emission rates, when operating under Scenario I: coal firing, coal and oil firing and the first hour when switching form Scenario I to Scenario II, set forth in the following table. [8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-01 (C1)	Unit 1 Boiler – Coal Fired	PM_{10}	714.0	3,127.4
		SO_2	10,440.0	22,863.6
		VOC	35.0	153.3
		CO	1,342.5	5,880.2
		NO_x	6,090.0	26,674.2
		Lead	0.3	1.0

SN	Description	Pollutant	lb/hr	tpy
SN-02 (C2)	Unit 2 Boiler – Coal Fired	PM_{10}	714.0	3,127.4
		SO_2	10,440.0	22,863.6
		VOC	35.0	153.3
		CO	1,342.5	5,880.2
		NO_x	6,090.0	26,674.2
		Lead	0.3	1.0

a. The permittee shall not exceed the emission rates, when operating under Scenario I: coal firing, coal and oil firing and the first hour when switching form Scenario I to Scenario II, set forth in the following table. [8 CAR § 41-801 et seq. and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-01 (C1)	Unit 1 Boiler – Coal Fired	CO	1342.5	5,880.2
SN-02 (C2)	Unit 2 Boiler – Coal Fired	CO	1342.5	5,880.2

2. The permittee shall not exceed the emission rates, when operating under Scenario I: coal firing, coal and oil firing and the first hour when switching form Scenario I to Scenario II, set forth in the following table. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
SN-01 (C1)	Unit 1 Boiler – Coal Fired	PM	346.9	1519.6
		SAM	10.1	22.1
		Cyanide	1.35	5.75
		Hydrogen Chloride	43.20	92.00
		Hydrogen Fluoride	78.75	345.00
		Methylene Chloride	0.16	0.67
		Total Other HAPs	4.8	20.7
SN-02 (C2)	Unit 2 Boiler – Coal Fired	PM	346.9	1519.6
		SAM	10.1	22.1
		Cyanide	1.35	5.75
		Hydrogen Chloride	43.20	92.00
		Hydrogen Fluoride	78.75	345.00
		Methylene Chloride	0.16	0.67
		Total Other HAPs	4.8	20.7

3. SN-01 and SN-02 are subject to 40 C.F.R. § 60 Subpart D, Standards of Performance for fossil fuel-fired steam generators due to a heat input capacity of greater than 250

MMBtu/hr. Applicable provisions of Subpart D (Appendix A) include, but are not limited to the following [8 CAR § 41-204 and 40 C.F.R. § 60]:

a. PM emissions shall not exceed 0.10 lb/MMBtu. [8 CAR § 41-204 and 40 C.F.R. § 60.42(a)(1)]
b. Opacity shall not exceed 20 percent except for one six-minute period per hour of not more than 27 percent opacity and as except as provided by 40 C.F.R. §§ 60.8 and 60.11. [8 CAR § 41-204 and 40 C.F.R. § 60.42(a)(2)]
c. SO_2 emissions shall not exceed 1.2 lb/MMBtu. [8 CAR § 41-204 and 40 C.F.R. § 60.43]
d. NO_X emissions shall not exceed 0.70 lb/MMBtu. [8 CAR § 41-204 and 40 C.F.R. § 60.44(a)(3)]
e. The permittee shall install, calibrate, and maintain Continuous Emissions Monitoring Systems (CEMS) for NO_X, SO_2, CO_2, and opacity. The CO_2 monitor and analyzer serve as the diluent in this system. [8 CAR § 41-204 and 40 C.F.R. § 60.45(a)]
f. Excess opacity emissions are defined as any six minute period during which the average opacity emissions exceed 20%, except for one 6-minute average per hour of up to 27% opacity. [8 CAR § 41-204 and 40 C.F.R. § 60.45(g)(1)]
g. Excess SO_2 emissions are defined as any 3-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard under § 60.43. [8 CAR § 41-204 and 40 C.F.R. § 60.45(g)(2)]
h. Excess NO_X emissions are defined as any 3-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of NO_X as measured by a CEMS exceed the applicable standard under § 60.44. [8 CAR § 41-204 and 40 C.F.R. § 60.45(g)(3)]
i. Excess emission and monitoring system performance reports shall be submitted to the Division for every calendar quarter. Quarterly reports shall be postmarked by the 30th day following the end of the calendar quarter. Excess emissions are defined in § 60.45(g). [8 CAR § 41-204 and 40 C.F.R. § 60.45(g)]
j. Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in §60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§60.48Da and 60.49Da of subpart Da of 40 CFR Part 60. [8 CAR § 41-204 and 40 C.F.R. § 60.45(g)(4)]

4. The permittee shall maintain records which demonstrate compliance with the SO_2 emission limits set in Specific Conditions # 1 and #3. These records may be used by the Division for enforcement purposes. For Specific Condition #1 compliance shall be determined as the arithmetic average of three one-hour periods of SO_2 emissions as measured by the CEMS and converted to pounds per hour per 40 C.F.R. § 75. Data Substituted in accordance with 40 C.F.R. § 75 for missing and/or invalid data will not be

used for compliance with Specific Condition #1. For Specific Condition #3, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of SO_2 as measured by a CEMS and converted to pounds per MMBtu per 40 C.F.R. § 60. These records shall be kept on site and shall be provided to Division personnel upon request. Records shall be submitted in accordance with General Provision #7. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

5. The permittee shall maintain records which demonstrate compliance with the NO_X emission limits set in Specific Conditions #1 and #3. These records may be used by the Division for enforcement purposes. For Specific Condition #1, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of NO_X emissions as measured by the CEMS and converted to pounds per hour per 40 C.F.R. § 75. Data Substituted in accordance with 40 C.F.R. § 75 for missing and/or invalid data will not be used for compliance with Specific Condition #1. For Specific Condition #3, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of NO_X as measured by a CEMS and converted to pounds per MMBtu per 40 C.F.R. § 60. These records shall be kept on site and shall be provided to Division personnel upon request. Records shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

6. The permittee shall not cause to be discharged to the atmosphere from the boilers any emissions which exhibit an opacity greater than 20 percent when firing coal or No. 2 fuel oil. The opacity shall not exceed 20 percent (6-minute average), except for one 6-minute period per hour not to exceed 27 percent. Opacity exceedances shall be reported in accordance with Specific Condition #7. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

7. The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring opacity of emissions and all SO_2, NO_X, and CO_2 emissions from SN-01 and SN-02 and record the output of the system. The CO_2 monitor and analyzer serve as the diluent in this system. This CEMS shall comply with the Air Division's "Continuous Emission Monitoring Systems Conditions". A copy is provided in Appendix B. The permittee shall report all excess emissions as defined by 40 C.F.R. §§ 60.45(g)(1), (2), and (3) and in accordance with 40 C.F.R. 60.7(c).

   The permittee must report all excess emissions which are shown to be in excess of the SO_2 and NO_X limits in Specific Condition 1. Excess emissions of NSPS limits are defined in other conditions. For opacity, all exceedances must be reported in the quarterly reports including those attributable to startup, shutdown, and malfunction.

   The number of startup and shutdown occurrences that occur at this facility have historically ranged from 12 to 24 per year. In general, startup begins when the ID and FD fans are started with the intent to fire the unit. Normally, startup ends when the unit achieves stable operation and the following operating parameters are met: (1) the

electrostatic precipitator is placed in service, and (2) startup oil is no longer necessary to support combustion. Duct sweeps are usually considered a part of the startup operation. For these units, shutdown normally begins when the unit load or output is reduced with the intent of removing the unit from service, or when the unit trips as the result of sudden and unforeseen failure or malfunction. Shutdown ends when the unit is no longer combusting fuel and fan operation is no longer required. [8 CAR § 41-603, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

8. The permittee shall submit quarterly excess emissions and monitoring systems performance reports to the Division. The reports shall include the magnitude of excess emissions, date and time of commencement and completion of each time period of excess emissions, process operating time during reporting period, date and time of each period during which the CEMS were inoperative, identification of each period of excess emissions that occurs during startup, shutdown, and malfunctions of the units, nature and cause of any malfunction (if known), and the corrective action or preventative measure adopted. The permittee will send the reports electronically using https://eportal.adeq.state.ar.us or mail them to the address below:

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

    [8 CAR § 41-204 and 40 C.F.R. § 60.7]

9. The permittee shall ensure that all continuous emission and opacity monitoring systems are in operation and monitoring all unit emissions or opacity at all times that the affected unit combusts any fuel, except during periods of calibration, quality assurance, preventative maintenance or repair. [8 CAR § 41-204 and 40 C.F.R. § 75.10]

10. The permittee shall not exceed the emission rates, when operating under Scenario II: No. 2 fuel oil or bio-diesel firing, set forth in the following table. Compliance with the listed SO_2 emission limits shall be demonstrated by compliance with Specific Condition #12. Compliance with the listed NO_x emission limits shall be demonstrated by compliance with Specific Condition #13. Compliance with all other listed limits shall be demonstrated by burning only No. 2 fuel oil or biodiesel while operating in Scenario II. [8 CAR § 41-401 et seq. and 40 C.F.R. §§ 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
01 (C1)	Unit 1 Boiler – No. 2 Fuel Oil or Bio-diesel	PM_{10} SO_2 VOC CO NO_x Lead	24.1 518.3 1.9 36.5 175.2 0.01	105.6 2270.0 8.1 159.9 767.4 0.04
02 (C2)	Unit 2 Boiler – No. 2 Fuel Oil or Bio-diesel	PM_{10} SO_2 VOC CO NO_x Lead	24.1 518.3 1.9 36.5 175.2 0.01	105.6 2270.0 8.1 159.9 767.4 0.04

11. The permittee shall not exceed the emission rates, when operating under Scenario II: No. 2 fuel oil or bio-diesel firing, set forth in the following table. Compliance with the listed emission limits shall be demonstrated by burning only No. 2 fuel oil or biodiesel while operating in Scenario II. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
01 (C1)	Unit 1 Boiler – No. 2 Fuel Oil or Bio-diesel	PM SAM Total Other HAPs	14.6 8.0 0.48	64.0 34.8 2.07
02 (C2)	Unit 2 Boiler – No. 2 Fuel Oil or Bio-diesel	PM SAM Total Other HAPs	24.1 8.0 1.4 0.48	105.6 34.8 5.9 2.07

12. The permittee shall maintain records which demonstrate compliance with the SO_2 emission limits set in Specific Condition #10. These records may be used by the Division for enforcement purposes. For Specific Condition #10, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of SO_2 emissions as measured by the CEMS and converted to pounds per hour per 40 C.F.R. § 75. Data substituted in accordance with 40 C.F.R. § 75 for missing and/or invalid data will not be used for compliance with Specific Condition #10. These records shall be kept on site and shall be provided to Division personnel upon request. Records shall be submitted in accordance with General Provisions #6 and #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

13. The permittee shall maintain records which demonstrate compliance with the NO_X emission limits set in Specific Condition #10. These records may be used by the Division

for enforcement purposes. For Specific Condition #10, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of NO_X emissions as measured by the CEMS and converted to pounds per hour per 40 C.F.R. § 75. Data substituted in accordance with 40 C.F.R. § 75 for missing and/or invalid data will not be used for compliance with Specific Condition #10. These records shall be kept on site and shall be provided to Division personnel upon request. Records shall be submitted in accordance with General Provisions #6 and #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

14. The permittee may burn No. 2 fuel oil or bio-diesel during startup, shutdown, and malfunction. For all other No. 2 fuel oil burning activities, the permittee shall submit a request to EPA for a determination regarding the applicability of NSPS Subpart D limits and testing requirements during the coal and fuel oil and fuel oil only firing scenarios. Within 30 days of permit issuance, this request shall be submitted to EPA and a copy shall be submitted to the Division. The facility submitted a request for determination on May 25, 2005. The permittee may burn No. 2 fuel oil or bio-diesel until a determination is made by EPA. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

15. 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 scenario under which the facility or source is operating. [40 C.F.R. 70.6(a)(9)(i), 8 CAR pt. 42.7, and in accordance with General Provision #17]

16. The permittee shall not exceed 45,727.2 tons/year of SO_2 emissions for any consecutive twelve month period from SN-01 and SN-02 when firing coal, No. 2 fuel oil or bio-diesel. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

17. The permittee shall maintain monthly records which demonstrate compliance with the limit set in Specific Condition #16. These records may be used by the Division for enforcement purposes. The records shall be updated no later than the last day of the month following the month to which the records pertain. The records shall be kept on site, and shall be provided to Division personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

18. The permittee shall not exceed 53,348.4 tons/year of NO_X emissions for any consecutive twelve-month period from SN-01 and SN-02 combined when firing coal or No. 2 fuel oil or bio-diesel. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

19. The permittee shall maintain monthly records which demonstrate compliance with the limit set in Specific Condition #18. These records may be used by the Division for enforcement purposes. The records shall be updated no later than the last day of the month following the month to which the records pertain. The records shall be kept on site, and shall be provided to Division personnel upon request. A twelve month rolling

total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

20. SN-01 and SN-02 are subject to and shall comply with all applicable provisions of the Acid Rain Program. [8 CAR § 41-204 and 40 C.F.R. §§ 72, 73, 75, 76, and 77]

21. The permittee shall submit the required Electronic Data Reports to EPA Headquarters. [Rule 19.304 and 40 C.F.R. § 75]

22. The permittee will perform Relative Accuracy tests in accordance with 40 C.F.R. § 75. This relative accuracy test will meet the requirements under 40 C.F.R. § 60, Subpart D. [Rule 19.304 and 40 C.F.R. § 75.10]

23. The permittee shall determine and record the heat input to each affected unit (SN-01 and SN-02) for every hour or part of an hour any fuel is combusted following the procedures in Appendix F of 40 C.F.R. § 75. This calculation will meet the requirements under 40 C.F.R. § 60, Subpart D. [8 CAR § 41-204 and 40 C.F.R. § 75.10(c)]

24. [Reserved]

25. The permittee shall test SN-01 and SN-02 for PM and PM_{10} while operating under Scenario I: Coal Firing without any oil firing (except for flame stabilization, to change bowl mills or other activities) and while operating at 90% or greater capacity. Emission results shall be extrapolated to correlate with 100% of the permitted capacity to determine compliance. The PM test shall be performed using EPA Reference Methods (RM) 5 and 202. The PM_{10} test shall be performed using EPA RMs 201A and 202. As an alternative to RM 201A for PM_{10}, the permittee may utilize RM 5 and assume all PM collected per RM 5 is PM_{10}. As a further alternative to both RM 5 and/or RM 201A, the permittee may elect to operate a certified filterable particulate matter continuous emission monitor (CEMS). If the permittee elects to utilize PM CEMS to demonstrate compliance with the applicable filterable PM limits of this permit, then no additional filterable (RM5/201A) testing shall be required provided that the permittee assumes that all filterable PM measured by such CEMS is PM_{10}. If a filterable PM CEMS is used in lieu of RM5 and/or RM201A testing, the permittee shall still conduct stack testing for condensable PM using RM 202. These tests shall be conducted in accordance with Plantwide Condition #3. This testing shall be conducted within 180 days of issuance of permit #0263-AOP-R7 and every year thereafter. [8 CAR § 41-602 and 40 C.F.R. § 52 Subpart E]

26. The ash content of the coal or coal blend shall not exceed 15.09 lb/MMBtu and the sulfur content of the coal or coal blend shall not exceed 0.72%, unless the following equation can be met:

$$[((0.1 \times S) - 0.03) \times 8950] + [(10 \times (1-0.995) \times A \times 8950 \times (1/C))] \leq 714.0 \text{ lb/hr}$$

where S = sulfur %,
A = ash %, and
C = coal heat value in MMBtu/ton.

The permittee shall maintain records that demonstrate compliance with this specific condition. These records shall include the certificate of analysis and, if applicable, the calculation results. If blending is necessary, the permittee shall also keep records of the data used to obtain the blended coal properties. If coal samples are used to demonstrate compliance with blended coal, the sampling method must be approved in advance by the Division. These records shall be kept on site and made available to Division personnel upon request. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

27. The permittee shall monitor the opacity of SN-01 and SN-02 using a continuous opacity monitoring system. The permittee shall initiate corrective action when the measured opacity is greater than 20% for a one-hour average, and shall report any excursions where the opacity is greater than 20% on a three-hour average. Corrective action may include, but is not limited to, ESP inspection, returning tripped ESP sections to service, ash removal system evaluation, and load reduction, if necessary. During startup when the ESP is offline, the corrective actions referenced above will not be required but startup shall be minimized. The permittee shall maintain records of the measured opacity and any corrective actions taken. A monitoring report shall be submitted to the Division in accordance with General Provision #7 and shall include the following per 40 C.F.R. § 64.9(a)(2):

The information required under 40 C.F.R. § 70.6(a)(3)(iii);

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

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

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

All opacity exceedances must be reported in the quarterly reports including those attributable to startup, shutdown, and malfunction. Opacity exceedances would not be

reported under §19.601 of 8 CAR pt. 41 for startup, shutdown, and malfunction. In accordance with §64.7(d)(2), a determination may be made by the Division regarding whether the permittee has used acceptable procedures in response to an excursion or an exceedance. [8 CAR § 41-204 and 40 C.F.R. § 64]

28. The opacity for SN-01 and SN-02 shall not exceed 20% opacity except that emissions greater than 20% opacity but not exceeding 60% opacity will be allowed for not more than six (6) minutes in the aggregate in any consecutive 60-minute period, provided such emissions will not be permitted more than three (3) times during any 24-hour period. However, the opacity limits imposed by this condition will be held in abeyance provided that opacity does not exceed 20% except that emissions greater than 20% opacity but not exceeding 27% opacity will be allowed for not more than one 6-minute period per hour, provided such emissions will not be permitted more than ten (10) times per day. Violations of this condition may be allowed as a direct result of unavoidable upset conditions in the nature of the process, or unavoidable and unforeseeable breakdown of any air pollution control equipment or related operating equipment, or as a direct result of shutdown or start-up of the operating unit, provided the following requirements are met:

    a. Such occurrence, in the case of unavoidable upset in or breakdown of equipment, shall have been reported to the Division by means of a notification delivered by phone, fax, or email by the end of the next business day after the discovery of the occurrence.

    b. The facility shall submit to the Division, at its request, a full report of such occurrence, including a statement of all known causes and of the scheduling and nature of the actions to be taken to minimize or eliminate future occurrences, including, but not limited to, action to reduce the frequency of occurrence of such conditions, to minimize the amount by which said limits are exceeded, and to reduce the length of time for which said limits are exceeded.

    c. In the case of shutdown for necessary scheduled maintenance, the intent to shutdown shall be reported to the Division at least twenty-four (24) hours prior to the shutdown; provided, however, that the exception provided by this condition shall only apply in those cases where maximum reasonable effort has been made to accomplish such maintenance during periods of non-operation of any related source operation or where it would be unreasonable or impossible to shut down the source operation during the maintenance period. Any information which is considered a trade secret under 8-4-308 shall be submitted with an affidavit containing the information of 8 CAR pt. 40.1402(B).

    d. Demonstrates to the satisfaction of the Division that the emissions resulted from:

        i. Equipment malfunction or upset and are not the result of negligence or improper maintenance;

ii. Physical constraints on the ability of a source to comply with the emission standard, limitation or rate during startup or shutdown;

And that all reasonable measures have been taken to immediately minimize or eliminate the excess emissions. Opacity exceedances shall be reported in accordance with Specific Conditions 7 and 8. [§18.102(C), §18.501, and §18.1101 of 8 CAR pt. 40 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

29. Unit 1 (SN-01) and Unit 2 (SN-02) are subject to and shall comply with all applicable requirements of 40 C.F.R. § 63 Subpart UUUUU - *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*. These requirements include those outlined in Specific Conditions #31 through #63 below. For the purposes of Subpart UUUUU, both Unit 1 and Unit 2 are categorized as existing coal-fired EGUs designed for a coal with a heating value greater than or equal to 8,300 Btu/lb. [8 CAR § 41-204 and 40 C.F.R. §§ 63.9981, 63.9982, and 63.9990]

30. [Reserved]

31. Unit 1 (SN-02) and Unit 2 (SN-02) shall comply with the applicable emission limits in Table 2 to Subpart UUUUU. For category (a) each unit shall comply with either the limit for filterable particulate matter, the limit for total non-Hg HAP metals, or the limits for individual HAP metals. For category (b) each unit shall comply with the limit for HCl. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), the permittee may elect to demonstrate compliance with either emission limit. These limits apply at all times except during periods of startup or shutdown; however for coal-fired EGUs, you are required to meet the work practice requirements, items 3 and 4, in Table 3 to 40 C.F.R. Subpart UUUUU during periods of startup or shutdown. [8 CAR § 41-204 and 40 C.F.R. §§ 63.9991and 63.10000(a)]

Table 2 Requirements for existing coal-fired EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb		
For the following pollutants. . .	You must meet the following emission limits and work practice standards. . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5. . .
a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.	Collect a minimum of 1 dscm per run.
OR	OR	
Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
OR	OR	

Table 2 Requirements for existing coal-fired EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb		
For the following pollutants. . .	You must meet the following emission limits and work practice standards. . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5. . .
Individual HAP metals:		Collect a minimum of 3 dscm per run.
Antimony (Sb)	8.0E-1 lb/Tbtu or 8.0E-3 lb/GWh.	
Arsenic (As)	1.1E0 lb/Tbtu or 2.0E-2 lb/GWh.	
Beryllium (Be)	2.0E-1 lb/Tbtu or 2.0E-3 lb/GWh.	
Cadmium (Cd)	3.0E-1 lb/Tbtu or 3.0E-3 lb/GWh.	
Chromium (Cr)	2.8E0 lb/Tbtu or 3.0E-2 lb/GWh.	
Cobalt (Co)	8.0E-1 lb/Tbtu or 8.0E-3 lb/GWh.	
Lead (Pb)	1.2E0 lb/Tbtu or 2.0E-2 lb/GWh.	
Manganese (Mn)	4.0E0 lb/Tbtu or 5.0E-2 lb/GWh.	
Nickel (Ni)	3.5E0 lb/Tbtu or 4.0E-2 lb/GWh.	
Selenium (Se)	5.0E0 lb/Tbtu or 6.0E-2 lb/GWh.	
b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run.
		For ASTM D6348-03 3or Method 320, sample for a minimum of 1 hour.
OR	OR	
Sulfur dioxide (SO_2) 4	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
c. Mercury (Hg)	1.2E0 lb/Tbtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

32. Unit 1 (SN-02) and Unit 2 (SN-02) shall comply with the applicable work practice standards in Table 3 to Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.9991(a)(1)]

Table 3 requirements for existing coal-fired EGUs	
If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup	You have the option of complying using either of the following work practice standards. (a)(1) If you choose to comply using paragraph (1) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g) and 63.10021(h) and (i).
	(2) If you choose to comply using paragraph (2) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup.
	For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e).

Table 3 requirements for existing coal-fired EGUs	
If your EGU is . . .	You must meet the following . . .
	Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits within 4 hours of start of electricity generation. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel.
	You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices.
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup	(c)If you choose to use just one set of sorbent traps to demonstrate compliance with Hg emission limits, you must comply with all applicable Hg emission limits at all times; otherwise, you must comply with all applicable emission limits at all times except for startup or shutdown periods conforming to this practice.
	(d)You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices.

Table 3 requirements for existing coal-fired EGUs	
If your EGU is . . .	You must meet the following . . .
	If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.
	You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031.

33. Unit 1 (SN-02) and Unit 2 (SN-02) shall comply with the applicable operating limits in Table 4 to Subpart UUUUU. These limits are only applicable to Units 1 and 2 if the permittee elects to utilize CPMS to demonstrate compliance with the applicable PM limit. [8 CAR § 41-204 and 40 C.F.R. § 63.9991(a)(1)]

Table 4 requirements for existing EGUs	
If you demonstrate compliance using. . .	You must meet these operating limits. . .
1. PM CPMS for an existing EGU	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of §63.40023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

34. The permittee shall meet the following general requirements of 40 C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10000]

a. Units 1 and 2 must be in compliance with the applicable emission limits and operating limits in 40 C.F.R. § 63 Subpart UUUUU. These limits apply at all times except during periods of startup or shutdown. The applicable work practice requirements of Table 3, items 3 and 4, must be met during periods of startup and shutdown. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(a)]

b. At all times Units 1 and 2 and any associated air pollution control equipment must be operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(b)]

c. As coal-fired units, initial performance testing is required for Units 1 and 2 for all pollutants, to demonstrate compliance with the applicable emission limits. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(c)]

i. For coal-fired EGUs you may conduct initial performance testing in accordance with § 63.10005(h) to determine whether the unit qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits. The exceptions of § 63.10000(c)(1)(i)(A) and (B) are not applicable to Units 1 and 2.

ii. For a qualifying LEE for Hg emissions limits, a 30-day performance test using Method 30B must be conducted at least once every 12 calendar months to demonstrate continued LEE status.

iii. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

iv. If a coal-fired EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or compliance testing repeated quarterly.

v. If a coal-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), initial and continuous compliance may be demonstrated through the use of an HCl CEMS, installed and operated in accordance with Appendix B to Subpart UUUUU. As an alternative to HCl CEMS, initial and continuous compliance may be demonstrated by conducting an initial and periodic quarterly performance stack tests for HCl.

vi. For a coal-fired EGU which does not qualify as a LEE for Hg, initial and continuous compliance must be demonstrated through the use of a Hg

CEMS or a sorbent trap monitoring system, in accordance with Appendix A to Subpart UUUUU.

1. The permittee may choose to use separate sorbent trap monitoring systems to comply with Subpart UUUUU: one sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown and the other sorbent trap monitoring system to report average mercury concentrations during startup periods or shutdown periods.

2. The permittee may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emissions limit at all times (including startup periods and shutdown periods) and to report average mercury concentration. The permittee must follow the startup or shutdown requirements of Table 3 to Subpart UUUUU for coal-fired EGUs (SN-01 and SN-02).

d. If compliance is demonstrated with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies if the permittee petitions the Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to 40 C.F.R. § 60 or 40 C.F.R. § 75 and that meet the requirements of § 63.10010. Using the process described in § 63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in § 63.10000(d) and, if approved, include those in the site-specific monitoring plan. The monitoring plan must address the provisions in §§ 63.10000(d)(2) through (d)(5). [8 CAR § 41-204 and 40 C.F.R. § 63.10000(d)]

e. As part of the demonstration of continuous compliance, the permittee must perform periodic tune-ups of Unit 1 and Unit 2 according to § 63.10021(e). [8 CAR § 41-204 and 40 C.F.R. § 63.10000(e)]

f. On or before the date that SN-01 or SN-02 is subject to Subpart UUUUU, the permittee must install, certify, operate, maintain, and quality-assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. The permittee must collect, record, report, and maintain data

obtained from these monitoring systems during startup periods and shutdown periods. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(l)]

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36. For Unit 1 and Unit 2, initial compliance must be demonstrated with each applicable emissions limit in Table 2 of 40 C.F.R. § 63 Subpart UUUUU through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), the permittee may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to 40 C.F.R. § 63 Subpart UUUUU; and CMS performance evaluations. In all cases, the permittee must demonstrate initial compliance no later than the applicable date in paragraph (f) of § 63.10005 for tune-up work practices for existing EGUs and by April 16, 2016 for other requirements for existing EGUs. [8 CAR § 41-204; and 40 C.F.R. § 63.10005]

a. To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of § 63.10005 and Table 4 to 40 C.F.R. § 63 Subpart UUUUU), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(a)(1)]

b. To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (i.e. , an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test consists of 30- (or, if emissions averaging for Hg is used, 90-) boiler operating days. If the CMS is certified prior to the compliance date (or, if applicable, the approved extended compliance date), the test shall begin with the first operating day on or after that date, except as otherwise provided in paragraph (b) of §63.10005. If the CMS is not certified prior to the compliance date, the test shall begin with the first operating day after certification testing is successfully completed. In all cases, the initial 30- or 90- operating day averaging period must be completed on or before the date that compliance must be demonstrated (i.e., 180 days after the applicable compliance date. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(a)(2)]

i. The CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 2 to 40 C.F.R. § 63 Subpart UUUUU.

ii. The permittee must collect hourly data from auxiliary monitoring systems (i.e., stack gas flow rate, CO_2, O_2, or moisture, as applicable) during the performance test period, in order to convert the pollutant concentrations to units of the standard. If the permittee chooses to comply with an electrical output-based emission limit, hourly electrical load data must be collected during the performance test period

37. If the permittee chooses to use performance testing to demonstrate initial compliance with the applicable emission limits in Table 2 to Subpart UUUUU for Unit 1 and/or Unit 2, the tests must be conducted according to § 63.10007 and Table 5 to Subpart UUUUU. For the purposes of the initial compliance demonstration, test data and results from a performance test conducted prior to the date on which compliance is required may be used, provided that the conditions of §§ 63.10005(b)(1) through (5) are fully met. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(b)]

38. If, for a particular emission or operating emission limit, the permittee is required to (or elects to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under Subpart UUUUU. [8 CAR § 41-204 and § 63.10005(d)]

a. For an affected coal-fired EGU, initial compliance with the applicable SO_2 or HCl emissions limit in Table 2 to Subpart UUUUU may be demonstrated through use of an SO_2 or HCl CEMS installed and operated in accordance with 40 C.F.R. § 75 or Appendix B to Subpart UUUUU. Compliance with a filterable PM emissions limit in Table 2 of Subpart UUUUU may be demonstrated through use of a PM CEMS installed, certified, and operated in accordance with § 63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see § 63.10007(e)), meets the applicable SO_2, PM, or HCl emissions limit in Table 2 to Subpart UUUUU. Equation 19-19 of Method 19 in Appendix A-7 to Subpart UUUUU must be used to calculate the 30-boiler operating day average emissions rate. For this calculation, the term Ehj in Equation 19-19 must be in the same units of measure as the applicable HCl emission limit in Table 2 of Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(d)(1)]

b. For affected coal-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table

2 to Subpart UUUUU using initial performance testing and continuous monitoring with PM CPMS: [8 CAR § 41-204 and 40 C.F.R. § 63.10005(d)(2)]

i. Initial compliance must be demonstrated by no later than the applicable date specified in § 63.9984(f) for existing units. Based on the compliance date extension granted by ADEQ, initial compliance for Unit 1 and Unit 2 must be demonstrated by no later than October 13, 2016.

ii. Continuous compliance must be demonstrated with the PM CPMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the emission limit with which the permittee chooses to comply.

iii. The permittee must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

c. For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 2 of Subpart UUUUU using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs. Based on the compliance date extension granted by ADEQ, initial compliance for Unit 1 and Unit 2 must be demonstrated by no later than October 13, 2016. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of Appendix A to Subpart UUUUU), meets the applicable Hg emission limit in Table 2 to Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(d)(3)]

39. Unit 1 and Unit 2 are subject to the work practice standards in Table 3 of Subpart UUUUU. As part of the initial compliance demonstration, the permittee must conduct a performance tune-up of Unit 1 and Unit 2 according to § 63.10021(e). [8 CAR § 41-204 and 40 C.F.R. § 63.10005(e)]

40. For an existing EGU without a neural network, a tune-up, following the procedures in §63.10021(e), must occur within 6 months (180 days) after April 16, 2015. For an existing EGU with a neural network, a tune-up must occur within 18 months (545 days) after April 16, 2016. If a tune-up occurs prior to April 16, 2015, the source must maintain adequate records to show that the tune-up met the requirements of this standard. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(f)]

41. If the permittee wishes to qualify for low emitting EGU (LEE) status for one or more pollutants with emission limits for existing EGUs, then the procedures of 40 C.F.R. §§ 63.10005(h)(1) through (5) must be followed, as applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(h)]

42. Startup and shutdown of Unit 1 and Unit 2 must follow the requirements given in Table 3 to 40 C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. §§ 63.10005(j); and 63.10011(g)]

    a. The permittee may use the diluent cap and default electrical load values, as described in 40 C.F.R. § 63.10007(f), during startup periods or shutdown periods. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(g)(1)]

    b. The permittee must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods and shutdown periods. [8 CAR § 41-204 and 40 C.F.R. § 63.1011(g)(2)

    c. The permittee must report the information as required in 40 C.F.R. § 63.10031. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(g)(3)]

    d. If the permittee choses to use paragraph (2) of the definition of "startup" in 40 C.F.R. § 63.10042 and finds that the facility is unable to safely engage and operate the particulate matter (PM) control(s) within 1 hour of first firing of coal, the permittee may choose to rely on paragraph (1) of the definition of "startup" in § 63.10042 or may elect to submit a request to use an alternative non-opacity emissions standard, as described in 40 C.F.R. §§ 63.10011(g)(4)(i) through (vii). [8 CAR § 41-204 and 40 C.F.R. § 63.10011(g)(4)]

43. The permittee must submit a Notification of Compliance Status summarizing the results of the initial compliance demonstration, as provided in § 63.10030. [8 CAR § 41-204 and 40 C.F.R. §§ 63.10011(e) and 63.10005(k)]

44. The permittee shall comply with the following requirements for subsequent performance tests and tune-ups. [8 CAR § 41-204 and 40 C.F.R. § 63.10006]

    a. If the permittee elects to utilize PM CPMS to monitor continuous performance with an applicable emission limit as provided under § 63.10000(c), then all applicable performance tests must be conducted according to Table 5 to Subpart UUUUU and § 63.10007 at least once every year. [8 CAR § 41-204 and 40 C.F.R. § 63.10006(a)]

    b. For units meeting the LEE requirements of § 63.10005(h), the permittee must repeat the performance test once every three years (once every year for Hg) according to Table 5 of Subpart UUUUU and § 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur: [8 CAR § 41-204 and 40 C.F.R. § 63.10006(b)]

i. For all pollutant emission limits except for Hg, the permittee must conduct emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1).

ii. For Hg, the permittee must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with Appendix A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the permittee must conduct Hg emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1). The permittee must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

c. Except where paragraphs (a) or (b) of § 63.10006 apply, or where the permittee installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the permittee must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to Subpart UUUUU, §§ 63.10007, and 63.10000(c), except as otherwise provided in § 63.10021(d)(1). [8 CAR § 41-204 and 40 C.F.R. § 63.10006(c)]

d. Except where paragraph (b) of § 63.10006 applies, if the permittee does not utilize either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the permittee must conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1). [8 CAR § 41-204 and 40 C.F.R. § 63.10006(d)]

e. Time between performance tests: [Rule 19.304 and 40 C.F.R. §63.10006(f)]

i. Notwithstanding the requirements of §63.10021(d)(1), the requirements listed in paragraphs (g) and (h) of § 63.10006, and the requirements of paragraph (f) of §63.10006, performance tests must be completed as follows: [8 CAR § 41-204 and 40 C.F.R. § 63.10006(f)]

1. At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter;

2. For annual testing:

a. At least 320 calendar days, measured from the test's end date, must separate performance tests;

b. At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests;

c. At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests; and

3. At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years.

ii. For units demonstrating compliance through quarterly emission testing, you must conduct a performance test in the 4th quarter of a calendar year if your EGU has skipped performance tests in the first 3 quarters of the calendar year.

iii. If your EGU misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next test period, you must complete an additional performance test in that period as follows:

1. At least 15 calendar days must separate two performance tests conducted in the same quarter.

2. At least 107 calendar days must separate two performance tests conducted in the same calendar year.

3. At least 350 calendar days must separate two performance tests conducted in the same 3 year period.

f. If the permittee elects to demonstrate compliance using emissions averaging under § 63.10009, then the permittee must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of § 63.10006. [8 CAR § 41-204 and 40 C.F.R. § 63.10006(g)]

g. If a performance test on a non-mercury LEE shows emission in excess of 50 percent of the emission limit and if the permittee chooses to reapply for LEE status, then subsequent performance tests must be conducted at the appropriate frequency given in section (c) through (e) of § 63.10006 for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria. [8 CAR § 41-204 and 40 C.F.R. § 63.10006(h)]

h. As Unit 1 and Unit 2 are subject to an applicable tune-up work practice standard, then the permittee must conduct a performance tune-up for each unit according to § 63.10021(e). [8 CAR § 41-204 and 40 C.F.R. § 63.10006(i)]

i. For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in § 63.10021(e) must be conducted no more than 36 calendar months after the previous performance tune-up.

ii. For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in § 63.10021(e) must be conducted no more than 48 calendar months after the previous performance tune-up.

i. The permittee must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in § 63.10031. [8 CAR § 41-204 and 40 C.F.R. § 63.10006(j)]

45. When conducting performance tests for the purposes of Subpart UUUUU, the permittee shall comply with the applicable provisions of 40 C.F.R. § 63.10007. [8 CAR § 41-204 and 40 C.F.R. § 63.10007]

46. If the permittee elects to utilize emissions averaging for the purposes of demonstrating compliance with the applicable emission limitations of Subpart UUUUU, the applicable provisions of 40 C.F.R. § 63.10009 shall be followed. [8 CAR § 41-204 and 40 C.F.R. §§ 63.10009 and 63.10011 (e)]

47. The permittee shall comply with the applicable monitoring, installation, operation, and maintenance requirements of 40 C.F.R. § 63.10010. Both Unit 1 and Unit 2 utilize single-unit single-stack configurations. [8 CAR § 41-204 and 40 C.F.R. § 63.10010]

48. The permittee must demonstrate initial compliance with each applicable emission limit of Subpart UUUUU by conducting performance testing. [8 CAR § 41-204 and 40 C.F.R. § 63.10011]

49. If the permittee is subject to an operating limit in Table 4 to Subpart UUUUU, demonstrates compliance with HAP metals or filterable PM emissions limit(s) through performance stack tests, and elects to use a PM CPMS to demonstrate continuous performance, then the permittee must also establish a site-specific operating limit, in accordance with Table 4 to Subpart UUUUU, § 63.10007, and Table 6 to Subpart UUUUU. The permittee may use only the parametric data recorded during successful performance tests (*i.e*, tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(b)]

50. If the permittee uses CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the first 30-boiler operating day (or, if alternate emissions averaging is used for Hg, the 90-boiler operating day) rolling average emission rate obtained with

certified CEMS expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 2 to Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(c)(1)]

51. For a unit that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or filterable PM emission limit in Table 2 of Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(c)(2)]

52. For candidate LEE units, the permittee shall use the results of the performance testing described in § 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 2 to Subpart UUUUU and to determine whether the unit qualifies for LEE status. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(d)]

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54. The permittee must determine the fuel whose combustion produces the least uncontrolled emissions, i.e., the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown. The determination of the cleanest fuel may take safety considerations into account. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(f)]

55. The permittee shall monitor and collect data to demonstrate continuous compliance in accordance with § 63.10020. [8 CAR § 41-204 and 40 C.F.R. § 63.10020]

56. The permittee must demonstrate continuous compliance with each applicable emissions limit, operating limit, and work practice standard in Tables 2 through 4 to 40 C.F.R. § 63 Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 to 40 C.F.R. § 63 Subpart UUUUU and paragraphs (b) through (i) of § 63.10021. [8 CAR § 41-204; and 40 C.F.R. § 63.10021]

    a. Except as otherwise provided in § 63.10020(c), if the permittee uses a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or uses a sorbent trap monitoring system to measure Hg emissions, continuous compliance must be demonstrated by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2 , or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Equation 8 of 40 C.F.R. § 63 Subpart UUUUU should be used to determine the 30- (or, if

applicable, 90-) boiler operating day rolling average. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(b)]

b. If the permittee uses a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control must be recorded. Continuous compliance must be demonstrated by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Equation 9 of 40 C.F.R. § 63 Subpart UUUUU should be used to determine the 30 boiler operating day average. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(c)]

c. If the permittee uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 to 40 C.F.R. § 63 Subpart UUUUU, [8 CAR § 41-204 and 40 C.F.R. § 63.10021(d)]

    i. The permittee may skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year; and

    ii. The permittee must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard.

d. If the permittee must conduct periodic performance tune-ups of affected EGUs, as specified in paragraphs (e)(1) through (9) of § 63.10021, perform the first tune-up as part of the initial compliance demonstration for the affected EGU. Notwithstanding this requirement, the first burner inspection may be delayed until the next scheduled unit outage provided that the requirements of § 63.10005 are met. Subsequent inspections of the burner must be performed at least once every 36 calendar months unless the EGU employs neural network combustion optimization during normal operations in which case an inspection of the burner and combustion controls must be performed at least once every 48 calendar months. If a unit is offline when a deadline to perform the tune-up passes, then the tune-up work practices shall be performed within 30 days after the re-start of the affected unit. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(e)]

e. The permittee must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client

Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(f)]

f. The permittee must report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 to 40 C.F.R. § 63 Subpart UUUUU or failed to conduct a required tune-up. These instances are deviations from the requirements of 40 C.F.R. § 63 Subpart UUUUU. These deviations must be reported according to § 63.10031. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(g)]

g. Unit 1 and Unit 2 must follow the startup or shutdown requirements as given in Table 3 to 40 C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(h)]

    i. The permittee may use the diluent cap and default electrical load values, as described in 40 C.F.R. § 63.10007(f), during startup periods and shutdown periods.

    ii. The permittee must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

    iii. The permittee may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of "startup" in §63.10042.

h. If the permittee relies on paragraph 2 of the definition of startup in 40 CFR 63.10042, the permittee must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in your semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, you must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i). [8 CAR § 41-204 and 40 C.F.R. § 63.10021(i)]

57. If the permittee elects to utilize the emission averaging provision, continuous compliance shall be demonstrated in accordance with § 63.10022. [8 CAR § 41-204 and 40 C.F.R. § 63.10022]

58. If the permittee elects to utilize PM CPMS, the operating limit shall be established according to § 63.10023(a) and (b). Continuous compliance shall be demonstrated according to § 63.10023(c). [8 CAR § 41-204 and 40 C.F.R. § 63.10023]

59. The permittee shall submit the following notifications. [8 CAR § 41-204; and 40 C.F.R. § 63.10030]

    a. The permittee shall submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and (6), and 63.9(b) through (h), as applicable, by the dates specified. [8 CAR § 41-204 and 40 C.F.R. § 63.10030(a)]

    b. The permittee shall submit an initial notification for Unit 1 and Unit 2 by not later than 120 days after April 16, 2012. [8 CAR § 41-204 and 40 C.F.R. § 63.10030(b)]

    c. When the permittee is required to conduct a performance test, a Notification of Intent to conduct a performance test must be submitted at least 30 days before the performance test is scheduled to begin. [8 CAR § 41-204 and 40 C.F.R. § 63.10030(d)]

    d. When required to conduct an initial compliance demonstration as specified in § 63.10011(a), the permittee must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). The Notification of Compliance Status report must contain the information specified in paragraphs (e)(1) through (8) to § 63.10030, as applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.10030(e)]

60. The permittee shall submit the following reports. [8 CAR § 41-204; and 40 C.F.R. § 63.10031]

    a. The permittee must submit each report in in § 63.10031 as applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(a)]

        i. If the permittee is required to (or elects to) monitor Hg emissions continuously, the permittee must meet the electronic reporting requirements of appendix A to 40 C.F.R. § 63 Subpart UUUUU.

        ii. If the permittee elects to monitor HCl and/or HF emissions continuously, the permittee must meet the electronic reporting requirements of appendix B to 40 C.F.R. § 63 Subpart UUUUU. Notwithstanding this requirement, if the permittee opts to certify its HCl monitor according to Performance Specification 18 in appendix B to part 60 of 40 C.F.R Chapter I and to use

Procedure 6 in appendix F to part 60 of 40 C.F.R Chapter I for on-going QA of the monitor, then, on and prior to December 31, 2023, report only hourly HCl emissions data and the results of daily calibration drift tests and relative accuracy test audits (RATAs) performed on or prior to that date; keep records of all of the other required certification and QA tests and report them, starting in 2024.

iii. If the permittee elects to monitor filterable PM emissions continuously, the permittee must meet the electronic reporting requirements of appendix C to 40 C.F.R. § 63 Subpart UUUUU. Electronic reporting of hourly PM emissions data shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial PM CEMS correlation test.

iv. If the permittee elects to demonstrate continuous compliance using a PM CPMS, the permittee must meet the electronic reporting requirements of appendix D to 40 C.F.R. § 63 Subpart UUUUU. Electronic reporting of the hourly PM CPMS output shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS.

v. If the permittee elects to monitor SO_2 emission rate continuously as a surrogate for HCl, the permittee must use the ECMPS Client Tool to submit the information listed in 40 CFR 63.10031(a)(5)(i), 40 CFR 63.10031(a)(5)(ii), and 40 CFR 63.10031(a)(5)(iii) to EPA (except where it is already required to be reported or has been previously provided under the Acid Rain Program or another emissions reduction program that requires the use of part 75 of 40 C.F.R Chapter I).

b. The permittee must submit semiannual reports according to the requirements in paragraphs (b)(1) through (5) of § 63.10031. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(b)]

i. The final semiannual compliance report shall cover the reporting period from July 1, 2023, through December 31, 2023. Quarterly compliance reports shall be submitted thereafter, in accordance with paragraph (g) of § 63.10031, starting with a report covering the first calendar quarter of 2024. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(b)(6)]

c. The semiannual compliance report must contain the information required in paragraphs (c)(1) through (10) of § 63.10031. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(c)]

d. Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in paragraph (c) of § 63.10031 must include the excess emissions and monitor downtime summary report described in 40 CFR 63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR 63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and you must, instead, include in the quarterly compliance reports described in paragraph (g) of § 63.10031 the applicable data elements in section 13 of appendix E to 40 C.F.R. § 63 Subpart UUUUU for any "deviation" (as defined in 40 CFR 63.10042 and elsewhere in this subpart) that occurred during the calendar quarter. If there were no deviations, you must include a statement to that effect in the quarterly compliance report [8 CAR § 41-204 and 40 C.F.R. § 63.10031(d)]

e. Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 C.F.R. 70.6(a)(3)(iii)(A) or 40 C.F.R. 71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to paragraphs (c) and (d) of § 63.10031, or two quarterly compliance reports covering the appropriate calendar half pursuant to paragraph (g) of § 63.10031, along with, or as part of, the semiannual monitoring report required by 40 C.F.R. § 70.6(a)(3)(iii)(A) or 40 C.F.R. § 71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(e)]

f. For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), you must submit a PDF test report in accordance with paragraph (f)(6) of § 63.10031, no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR 63.10031(g), submit the applicable reference method information in sections 17 through 31 of appendix E to 40 C.F.R. § 63 Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(f)]

g. Starting with a report for the first calendar quarter of 2024, the permittee must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections

2 through 13 of appendix E to 40 C.F.R. § 63 Subpart UUUUU. For each stack test summarized in the compliance report, the permittee must also submit the applicable reference method information in sections 17 through 31 of appendix E to 40 C.F.R. § 63 Subpart UUUUU. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(g)]

h. On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR 63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in paragraphs (f)(6)(i) through (xii) of § 63.10031 must be entered into ECMPS with each Notification. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(h)]

i. If the permittee has elected to use paragraph (2) of the definition of "startup" in 40 CFR 63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, the permittee must include the information in 40 CFR 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If the permittee has elected to use paragraph (2) of the definition of "startup" in 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, the permittee must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in paragraphs (f)(6)(i) through (xii) of § 63.10031 must be entered into ECMPS with each startup and shutdown report. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(i)]

j. If the permittee elects to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with 40 C.F.R. § 63 Subpart UUUUU and the permittee has begun recording valid data from the PM CEMS prior to November 9, 2020, the permittee must use the ECMPS Client Tool to submit a detailed report of its PS 11 correlation test (see appendix B to part 60 of 40 C.F.R Chapter I) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, the permittee must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, the permittee must submit the PDF report according to section 7.2.4 of appendix C to 40 C.F.R. § 63 Subpart UUUUU. The applicable data elements in paragraph (f)(6)(i) through (xii) of § 63.10031 must be entered into ECMPS with the PDF report. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(j)]

k. If the permittee elects to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, the permittee must submit quarterly reports of its QA/QC activities (e.g., calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter.

Otherwise, the permittee must submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraph (f)(6)(i) through (xii) of § 63.10031 must be entered into ECMPS with the PDF report. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(k)]

61. The permittee shall keep the following records. [8 CAR § 41-204; and 40 C.F.R. § 63.10032]

a. The permittee must keep records of the items outlined in paragraphs (a)(1) and (2) of § 63.10032. If the permittee is required to (or elects to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if the permittee elects to use a PM CPMS, the records required under Appendix A and/or Appendix B and/or Appendix C and/or Appendix D to 40 C.F.R. § 63 Subpart UUUUU must also be kept. If the permittee elects to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the permittee must keep records of the applicable data elements under 40 CFR 63.7(g). The permittee must also keep records of all data elements and other information in appendix E to 40 C.F.R. § 63 Subpart UUUUU that apply to the permittee's compliance strategy. [8 CAR § 41-204 and 40 C.F.R. § 63.10032(a)]

i. In accordance with 40 CFR 63.10(b)(2)(xiv), a copy of each notification or report submitted to comply with Subpart UUUUU. The permittee must also keep records of all supporting documentation for the Initial Notification or Notification of Compliance Status, semiannual compliance reports, or quarterly compliance reports that are submitted

ii. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

b. For each CEMS and CPMS, the permittee must keep records according to paragraphs (b)(1) through (4) of § 63.10032. [8 CAR § 41-204 and 40 C.F.R. § 63.10032(b)]

i. Records described in § 63.10(b)(2)(vi) through (xi).

ii. Previous (i.e. superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

iii. Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

c. The permittee must keep the records required in Table 7 of 40 C.F.R. § 63 Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each applicable emission limit and operating limit. [8 CAR § 41-204 and 40 C.F.R. § 63.10032(c)]

d. For each EGU subject to an emission limit, the permittee must keep the records in paragraphs (d)(1) through (3) of § 63.10032. [8 CAR § 41-204 and 40 C.F.R. § 63.10032(d)]

i. The permittee must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 C.F.R. 241.3(b)(1), records must be kept which document how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 C.F.R. 241.3(b)(2), records must be kept as to how the operations that produced the fuel satisfies the definition of processing in 40 C.F.R. 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 C.F.R. 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process.

iii. For an EGU that qualifies as an LEE under § 63.10005(h), the permittee must keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

e. If the permittee elects to average emissions consistent with § 63.10009, then a copy of the emissions averaging implementation plan required in § 63.1009(g) must be kept, along with all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022. [8 CAR § 41-204 and 40 C.F.R. § 63.10032(e)]

f. Regarding startup periods and shutdown periods: [8 CAR § 41-204 and 40 C.F.R. § 63.10032(f)]

i. Should you choose to rely on paragraph (1) of the definition of "startup" in 40 C.F.R. §63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown.

ii. Should you choose to rely on paragraph (2) of the definition of "startup" in 40 C.F.R. §63.10042 for your EGU, you must keep records of:;

1. The determination of the maximum clean fuel capacity for each EGU; [8 CAR § 41-204 and 40 C.F.R. § 63.10032(f)(2)]

2. The determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and [8 CAR § 41-204 and 40 C.F.R. § 63.10032(f)(2)]

3. The information required in 40 C.F.R. § 63.10020(e). [8 CAR § 41-204 and 40 C.F.R. § 63.10032(f)(4)]

g. The permittee must keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. [8 CAR § 41-204 and 40 C.F.R. § 63.10032(g)]

h. The permittee must keep records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [8 CAR § 41-204 and 40 C.F.R. § 63.10032(h)]

i. The permittee must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown. [8 CAR § 41-204 and 40 C.F.R. § 63.10032(i)]

62. The permittee's records must be kept as follows. [8 CAR § 41-204 and 40 C.F.R. § 63.10033]

a. Records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1). [8 CAR § 41-204 and 40 C.F.R. § 63.10033(a)]

b. As specified in § 63.10(b)(1), each record must be kept for a period of 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [8 CAR § 41-204 and 40 C.F.R. § 63.10033(b)]

c. Each record must be kept on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record,

according to § 63.10(b)(1). The permittee can keep the records off-site for the remaining 3 years. [8 CAR § 41-204 and 40 C.F.R. § 63.10033(c)]

63. The general provisions of 40 C.F.R. §§ 63.1 through 63.15 are applicable as specified in Table 9 to Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10040]

64. The permittee shall sample and analyze each shipment of fuel oil or bio-diesel to determine the sulfur content. The sulfur content shall not exceed 0.5 weight percent. fuel oil sampling and analysis may be performed by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that sampling is performed according to ASTM D4057. A shipment shall be defined as a 5,000 or 10,000 barrel lot delivered to a pipeline and pumped to a loading rack. *(Note: Vendor testing would satisfy this requirement as long as the sampling is performed according to ASTM D4057 and the facility is able to meet the requirements of Specific Condition #65.)* [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

65. The permittee shall maintain records of fuel oil analysis. These records shall be kept on site and made available to Division personnel upon request. These records may be used by the Division for enforcement purposes. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

Prevention of Significant Deterioration for Low NO_X and Separated Overfire Air Project

66. The emissions from SN-01 and SN-02 shall not exceed the PSD emission limits in the following table when burning coal or No. 2 fuel oil. [8 CAR § 41-801 *et seq.*, and 40 C.F.R. § 52, Subpart E]

Sources	Pollutant	BACT Determination		
Each Coal Fired Unit (SN-01 and SN-02)	CO	Good Combustion Practices*	0.15 lb/MMBtu **	Bi-Annual Stack Testing (3-hour average)

* "Good combustion practices" means the boilers will be operated during coal-firing to obtain a good air/fuel mixture in the combustion zone as verified by periodic furnace observations, maintaining overall excess oxygen levels high enough to complete combustion while maximizing furnace thermal efficiency, and by providing sufficient residence time to complete combustion as provided by original equipment design.

** According to the equipment manufacturer, the emission limit is 0.15 lb CO/MMBtu which corresponds with 185 ppm measured at 3.0% O_2 on a dry basis.

67. The permittee shall test SN-01 and SN-02 for CO while operating under Scenario 1: Coal Firing on each unit once every six months. To provide flexibility in scheduling, such testing shall be conducted at least 120 days but no more than 240 days following the previous testing event, provided that CO testing is conducted during two out of each four successive calendar quarters. If a unit is offline at the time that testing would otherwise be required, then CO testing for that unit shall be conducted within 30 unit operating days

following resumption of operation following the date the test would otherwise have been required. These tests shall be performed using EPA Reference Method 10, and shall be conducted in accordance with Plantwide Condition #3. This testing shall be conducted while operating at 90% or greater capacity and consist of three one hour test periods averaged to demonstrate compliance with Specific Condition #66. [8 CAR § 41-602 and 40 C.F.R. § 52, Subpart E]

68. Reserved

69. The permittee shall not exceed 0.60 lb/MMBtu of SO_2 emissions from SN-01 and SN-02 each per rolling 30-boiler-operating-day averaging period. This limit shall become effective on August 6, 2021. [40 C.F.R. § 52.173]

70. The permittee shall permanently cease coal-fired operations on SN-01 and SN-02 by no later than December 31, 2028. [40 C.F.R. § 52.173]

71. The permittee demonstrates compliance with Specific Condition #69 by using data from a continuous emission monitoring system operated in accordance with Appendix B. [40 C.F.R. § 52.173]

72. No. 2 fuel oil or bio-diesel is the only fuel permitted for use in the Auxiliary boiler, SN-05. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

73. The permittee shall not exceed the emission rates set forth in the following table when burning No. 2 fuel oil or bio-diesel in the Auxiliary boiler, SN-05. The permittee demonstrates compliance with the BART requirements for SN-05 by complying with the hourly SO_2 and NOx, emission rates set forth in the following table. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
05 (C3)	Auxiliary Boiler	PM_{10}	4.5	19.4
		SO_2	95.2	416.8
		VOC	0.4	1.5
		CO	18.7	81.5
		NO_x	32.2	140.9
		Lead	0.01	0.01

74. The permittee shall not exceed the emission rates set forth in the following table when burning No. 2 fuel oil or bio-diesel in the Auxiliary boiler, SN-05. The permittee demonstrates compliance with the BART requirements for SN-05 by complying with the hourly PM emission rate set forth in the following table. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
05 (C3)	Auxiliary Boiler	PM	2.7	11.8
		SAM	1.5	6.4
		Hydrogen Chloride	0.21	0.89
		Total Other HAPs	0.09	0.38

75. The opacity shall not exceed 20% from SN-05 as measured by EPA Reference Method 9. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]

76. Weekly observations of the opacity from SN-05 shall be conducted by personnel familiar with the permittee's visible emissions, when operated during daylight hours for more than one continuous hour. The permittee shall keep records of these observations. The permittee shall maintain personnel trained in (but not necessarily certified in) EPA Reference Method 9. If visible emissions are detected, then the permittee shall conduct a 6-minute opacity reading in accordance with EPA Reference Method 9. Records of the opacity observations shall be updated weekly, maintained on site, and made available to Division personnel upon request. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

77. The auxiliary boiler (SN-05) shall not exceed an average annual capacity factor, determined on a calendar year basis, of 10%. Compliance with this condition shall establish SN-05 as a limited-use boiler pursuant to the provisions of 40 C.F.R. § 63 Subpart DDDDD. [8 CAR § 41-204 and 40 C.F.R. § 63.10032]

78. The permittee shall maintain monthly records for demonstrating compliance with Specific Condition #77. These records shall be updated monthly, maintained on site, and made available to Division personnel upon request. Compliance with Specific Condition #77 may be demonstrated through either of the following methods. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

    a. Maintaining records of the hours of operation of the auxiliary boiler (SN-05) and limiting the hours of operation to no more than 876 hours per calendar year; or

    b. Maintaining records of heat input to the auxiliary boiler (SN-05) and limiting the annual heat input to the auxiliary boiler (SN-05) to no more than 160,300 MMBtu per calendar year.

79. As an alternative to compliance with Specific Condition #77, the permittee may elect to remove the limited-use boiler classification for SN-05. In order to remove the limited-use classification for SN-05, the permittee shall submit written notification to ADEQ. This notification shall be provided by letter to the ADEQ Air Division Permits Branch Manager and shall include the date upon which SN-05 will begin to comply with the provisions of IB MACT Scenario 2. This notification shall be submitted at least 30 days prior to this date. If this notification is submitted, a copy shall be maintained on-site

along with the current air permit for the facility. Upon submittal of this notification, the permittee is no longer required to demonstrate compliance with Specific Conditions #77 and #78 as of the date that the unit begins to instead comply with the provisions of IB MACT Scenario 2. [8 CAR § 41-204 and 40 C.F.R. § 63.7499]

80. The auxiliary boiler (SN-05) is subject to and shall comply with all applicable requirements of 40 C.F.R. § 63 Subpart DDDDD - *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*. SN-05 must be in compliance with the applicable requirements of the subpart by January 31, 2016. For the purposes the subpart, SN-05 is categorized as an existing limited-use boiler. The applicable requirements include but are not limited to Specific Conditions #81 through #129. [8 CAR § 41-204 and 40 C.F.R. §§ 63.7485, 63.7490, 63.7495, and 63.7499]

Industrial Boiler MACT Provisions for Auxiliary Boiler (SN-05) Scenario I – Limited Use

81. As a limited-use boiler, the auxiliary boiler (SN-05) must complete a tune-up every five (5) years as specified in 40 C.F.R. § 63.7540(a)(12). SN-05 is not subject to the emission limits in Tables 1 and 2 or 11 through 13 to 40 C.F.R. § 63 Subpart DDDDD, the annual tune-up or the energy assessment requirements in Table 3 of Subpart DDDDD, or the operating limits in Table 4 of Subpart DDDDD. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. [8 CAR § 41-204 and 40 C.F.R. §§ 63.7500(c) and 63.7540(a)(12)]

82. The initial tune-up of SN-05 must be completed, following the procedures described in §§ 63.7540(a)(10)(i) through (vi), by no later than January 31, 2016. [8 CAR § 41-204 and 40 C.F.R. § 63.7510(e)]

83. The permittee shall maintain fuel use records for each day that SN-05 is in operation. [8 CAR § 41-204 and 40 C.F.R. § 63.7525(k)]

84. Each tune-up of the auxiliary boiler (SN-05) shall be conducted as specified in §§ 63.7540(a)(10)(i) through (vi). These requirements are summarized below:

    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). At units where entry into a piece of process equipment or a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(i)]

    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. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(ii)]

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). [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(iii)]

d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(iv)]

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. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(v)]

f. Maintain on-site and submit, if requested by the Administrator, an annual report containing the following information. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(vi)]

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 part of the tune-up; and

iii. The type and amount of fuel used over the 12 months prior to the tune-up, 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 used by each unit.

85. The burner inspection specified in § 63.7540(a)(10)(i) may be delayed until the next scheduled or unscheduled unit shutdown, but must be completed at least once every 72 months. [8 CAR § 41-204 and C.F.R. § 63.7540(a)(12)]

86. If SN-05 is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(13)]

87. The permittee shall report each instance in which the tune-up requirement, as listed in Table 3 of 40 C.F.R. § 63 Subpart DDDDD, is not met. These instances are deviations from the operating limits of Subpart DDDDD. These deviations must be reported in accordance with the requirements of § 63.7550. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(b)]

88. As SN-05 is a limited-use boiler subject only to a require to conduct a 5-year tune-up according to § 63.7540(a)(12) and is not subject emission limits or operating limits under 40 C.F.R. § 63 Subpart DDDDD, the permittee may submit a compliance report every five (5) years as specified in §§ 63.7550(b)(1) through (b)(4) instead of a semi-annual compliance report. This report must contain the information in §§ 63.7550(c)(5)(i) through (iv) and (xiv). [8 CAR § 41-204 and 40 C.F.R. §§ 63.7550(b) and 63.7550(c)(1)]

89. The permittee shall submit to the Administrator, for SN-05, all of the notifications in 40 C.F.R. §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to SN-05 by the dates specified. [8 CAR § 41-204 and 40 C.F.R. § 63.7545(a)]

90. As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013. [8 CAR § 41-204 and 40 C.F.R. § 63.7545(b)]

91. The permittee must submit each report in Table 9 to Subpart DDDDD as applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.7550(a)]

92. A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule The permittee shall include the following information in the compliance report:

    a. Company and Facility name and address.

    b. Process unit information, emissions limitations, and operating parameter limitations.

    c. Date of report and beginning and ending dates of the reporting period.

    d. The total operating time during the reporting period.

    e. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to §§ 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

93. All reports required by Table 9 of Subpart DDDDD (including the 5-year compliance report) must be submitted electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX). However, if the reporting form specific to this subpart is not available in CEDRI at the time the report is due, the report must be submitted to the Administrator at the appropriate address listed in 40 C.F.R. § 63.13. At the discretion of the Administrator, you must also submit these reports to the Administrator in the format specified by the Administrator. [8 CAR § 41-204 and 40 C.F.R. § 63.7550(h)(3)]

94. The permittee shall keep records according to paragraphs (a)(1) and (a)(2) of 40 C.F.R. § 63.7555. These records shall include: [8 CAR § 41-204 and 40 C.F.R. § 63.7555(a)]

    a. A copy of each notification and report that was submitted to comply with 40 C.F.R. § 63 Subpart DDDDD, including all documentation supporting any initial notification or notification of compliance status or semiannual compliance report that was submitted according to the requirements in § 63.10(b)(2)(xiv). [8 CAR § 41-204 and 40 C.F.R. § 63.7555(a)(1)]

    b. Records of performance tests, fuel analyses, and other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii)]

95. The permittee must maintain records in a form suitable and readily available for expeditious review, according to § 63.10(b)(1). [8 CAR § 41-204 and 40 C.F.R. § 63.7560(a)]

96. As specified in § 63.10(b)(1), the permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [8 CAR § 41-204 and 40 C.F.R. § 63.7560(b)]

97. The permittee must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years. [8 CAR § 41-204 and 40 C.F.R. § 63.7560(c)]

98. The permittee shall comply with the applicable provisions of the General Provisions in 40 C.F.R. §§ 63.1 through 63.15 as outlined in Table 10 to 40 C.F.R. § 63 Subpart DDDDD. [8 CAR § 41-204 and 40 C.F.R. § 63.7565]

Industrial Boiler MACT Provisions for Auxiliary Boiler (SN-05) Scenario 2 – Liquid/Light Liquid-Fired

99. The auxiliary boiler (SN-05) while operating under Scenario 2 will be classified as a unit designed to burn liquid fuel and a unit designed to burn light-liquid fuel. [8 CAR § 41-204 and 40 C.F.R. §§ 63.7499(q) and (u)]

100. The permittee must meet the requirements in 40 C.F.R. §§ 63.7500 (a)(1) through (3), except as provided in 40 C.F.R. §§ 63.7500 (b) through (e). The permittee must meet these requirements at all times the affected unit is operating, except as provided in 40 C.F.R. § 63.7500 (f). [8 CAR § 41-204 and 40 C.F.R. § 63.7500(a)]

101. The permittee shall meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to Subpart DDDDD except as provided under § 63.7522.

The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. [8 CAR § 41-204 and 40 C.F.R. § 63.7500(a)(1)]

Summary of IB MACT Emission Standards
for SN-05 Scenario II

Pollutant	Emissions Standard	Units for Emissions Standard
Filterable PM (or TSM*)	7.9E-03 (or 6.2E-03)	lb per MMBtu of heat input
CO	130	ppmvd corrected to 3% O_2
HCl*	1.1E-03	lb per MMBtu of heat input
Mercury*	2.0E-06	lb per MMBtu of heat input

* :HCl, TSM, and Mercury have the option to demonstrate compliance through fuel analysis.

a. The permittee shall comply with the following emission limits from Table 2 to § 63 Subpart DDDDD. [8 CAR § 41-204 and 40 C.F.R. § 63.7500(a)(1)]

Note: Only requirements applicable to SN-05 in Table 2 to Subpart DDDDD are repeated below.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06 lb per MMBtu of heat input	2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784b collect a minimum of 2 dscm.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.

b. The permittee shall comply with the following operating limits from Table 3 to § 63 Subpart DDDDD. [8 CAR § 41-204 and 40 C.F.R. § 63.7500(a)(1)]

Note: Only requirements applicable to SN-05 in Table 3 to Subpart DDDDD are repeated below.

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
4. An existing boiler or process heater located at a major source facility, not including limited use units	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. 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

If your unit is . . .	You must meet the following . . .
	energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas.
	If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable

If your unit is . . .	You must meet the following . . .
	control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose.
	You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown	You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR.
	You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

c. The permittee shall comply with the following operating limits from Table 4 to § 63 Subpart DDDDD, as applicable, for SN-05. [8 CAR § 41-204 and 40 C.F.R. § 63.7500(a)(2)]

Note: Only requirements applicable to SN-05 in Table 4 to Subpart DDDDD are repeated below.

When complying with a Table 1, 2, 11, 12, or 13	You must meet these operating limits . . .

numerical emission limit using . . .	
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. 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 § 63.7525(a).

102. At all times, the permittee must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator 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. [8 CAR § 41-204 and 40 C.F.R. § 63.7500(a)(3)]

103. The permittee must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to the permittee at all times the affected unit is operating except for the periods noted in § 63.7500(f). [8 CAR § 41-204 and 40 C.F.R. § 63.7505(a)]

104. The permittee shall demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.7505(c)]

105. The permittee may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. Otherwise, the permittee must demonstrate compliance for HCl, mercury, or TSM

using performance testing, if subject to an applicable emission limit. [8 CAR § 41-204 and 40 C.F.R. § 63.7505(c)]

106. If the permittee is required or elects to demonstrate, for SN-05, initial compliance with any applicable emission limits of Table 2 to § 63 Subpart DDDDD through the use of performance testing, then the initial compliance requirements include those outlined in 40 C.F.R. § 63.7510(a)(1) through (4), as applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.7510(a)]

a. The permittee shall conduct performance tests according to § 63.7520 and Table 5 to Subpart DDDDD. [8 CAR § 41-204 and 40 C.F.R. § 63.7510(a)(1)]

i. The permittee must conduct all performance tests according to § 63.7(c), (d), (f), and (h). [8 CAR § 41-204 and 40 C.F.R. § 63.7520(a)]

ii. The permittee must also develop a site-specific stack test plan according to the requirements in § 63.7(c). [8 CAR § 41-204 and 40 C.F.R. § 63.7520(a)]

iii. The permittee shall conduct all performance tests under such conditions as the Administrator specifies based on the representative performance of each boiler or process heater for the period being tested. Upon request, the permittee shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. [8 CAR § 41-204 and 40 C.F.R. § 63.7520(a)]

iv. The permittee must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. The permittee must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if the permittee opts to comply with the TSM alternative standard and the permittee must demonstrate initial compliance and establish the permittee's operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, the permittee must comply with the operating limit for operating load conditions specified in Table 4 to this subpart. [8 CAR § 41-204 and 40 C.F.R. § 63.7520(c)]

Note: Only requirements applicable to SN-05 in Table 7 to Subpart DDDDD are repeated below.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520	(1) Data from the oxygen analyzer system specified in § 63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load 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.

v. The permittee must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart. [8 CAR § 41-204 and 40 C.F.R. § 63.7520(d)]

vi. To determine compliance with the emission limits, the permittee must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 C.F.R. part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates. [8 CAR § 41-204 and 40 C.F.R. § 63.7520(e)]

vii. If measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), the permittee must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level. [8 CAR § 41-204 and 40 C.F.R. § 63.7520(f)]

b. The permittee shall establish operating limits according to § 63.7530 and Table 7 to this subpart. [8 CAR § 41-204 and 40 C.F.R. § 63.7510(a)(3)]

c. The permittee shall conduct CMS performance evaluations according to § 63.7525. [8 CAR § 41-204 and 40 C.F.R. § 63.7510(a)(4)]

d. While operating under Scenario II, SN-05 is subject to a CO emission limit in Tables 2 to Subpart DDDDD. The permittee must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or the permittee must install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in §§ 63.7525(a)(1) through (7). [8 CAR § 41-204 and 40 C.F.R. § 63.7525(a)]

e. The permittee shall operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

107. The permittee must establish operating parameter limits, for SN-05, according to §§ 63.7530(b)(4)(i) through (ix), as applicable. As indicated in Table 4 to 40 C.F.R. § 63 Subpart DDDDD, the permittee is not required to establish and comply with the operating parameter limits when a CEMS is used to monitor and demonstrate compliance with the applicable emission limit for that control device parameter. [8 CAR § 41-204 and 40 C.F.R. § 63.7530(b)(4)]

108. If the permittee elects to demonstrate compliance with an applicable emission limit through fuel analysis, the fuel analysis must be conducted according to 40 C.F.R. § 63.7521 and must follow the procedures in §§ 63.7530(c)(1) through (5). [8 CAR § 41-204 and 40 C.F.R. § 63.7530(c)]

109. The permittee must submit a notification of compliance status, for SN-05, containing the results of the initial compliance demonstration according to the requirements of 40 C.F.R. § 63.7545(e). [8 CAR § 41-204 and 40 C.F.R. § 63.7530(f)]

110. The permittee must meet, for SN-05, the work practice standard according to Table 3 of 40 C.F.R. § 63 Subpart DDDDD. During startup and shutdown, the permittee must only follow the work practice standards according to item 5 of Table 3 to Subpart DDDDD. [8 CAR § 41-204 and 40 C.F.R. §§ 63.7530(h) and 63.7540(d)]

111. The permittee must, for SN-05, monitor and collect data according to 40 C.F.R. § 63.7535 and the site-specific monitoring plan required by § 63.7505(d). [8 CAR § 41-204 and 40 C.F.R. § 63.7535(a)]

112. The permittee must, for SN-05, demonstrate continuous compliance with each applicable emission limit in Table 2 to 40 C.F.R. § 63 Subpart DDDDD, the applicable work practice standards in Table 3 to Subpart DDDDD, and the applicable operating limits in Table 4 to Subpart DDDDD according to the methods specified in Table 8 to Subpart DDDDD and 40 C.F.R. § 63.7540(a)(1) through (19). [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)]

113. Following the date on which the initial compliance demonstration for SN-05 is completed or required to be completed under 40 C.F.R. §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 to 40 C.F.R. § 63 Subpart DDDDD except during performance tests conducted to determine compliance with emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(1)]

114. As specified in 40 C.F.R. § 63.7550(c), the permittee must keep records of the type and amount of each fuel burned in SN-05 during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would meet either of the following criteria. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(2)]

a. Lower emissions of HCl and mercury than the applicable emission limit for each pollutant, if compliance is demonstrated through fuel analysis.

b. Lower fuel input of chlorine and mercury than the maximum values calculated during the last performance test, if compliance is demonstrated through performance testing.

115. If the permittee demonstrates compliance, for SN-05, with an applicable HCl emission limit through fuel analysis for a liquid fuel and plans to burn a new type of liquid fuel, the permittee must recalculate the HCl emission rate using Equation 12 of 40 C.F.R. § 63.7530 according to §§ 63.7540(a)(3)(i) through (iii). Fuel analysis is not required for the fuels described in §§ 63.7510(a)(2)(i) through (iii). The fuels described in §§ 63.7510(a)(2)(i) through (iii) may be excluded when recalculating the HCl emission rate. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(3)]

116. If the permittee elects, for SN-05, to demonstrate compliance with the applicable alternative CO CEMS emission limitation listed in Table 2 to 40 C.F.R. § 63 Subpart DDDDD, then the permittee must meet the requirements in 40 C.F.R. §§ 63.7540(a)(8)(i) through (iv). [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(8)]

117. Each tune-up of the auxiliary boiler (SN-05) shall be conducted as specified in §§ 63.7540(a)(10)(i) through (vi). These requirements are summarized below:

a. As applicable, inspect the burner, and clean or replace and components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(i)]

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. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(ii)]

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). [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(iii)]

d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(iv)]

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. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(v)]

f. Maintain on-site and submit, if requested by the Administrator, an annual report containing the following information. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(10)(vi)]

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 part of the tune-up; and

iii. The type and amount of fuel used over the 12 months prior to the tune-up, 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 used by each unit.

118. If SN-05 has a continuous oxygen trim system which maintains an optimum air to fuel ratio, then a tune-up of the boiler must be conducted every five (5) years as specified in 40 C.F.R. § 63.7540(a)(12). The burner inspection specified in § 63.7540(a)(10)(i) may be delayed until the next scheduled or unscheduled unit shutdown, but must be completed at least once every 72 months. [Rule 19.304 and C.F.R. § 63.7540(a)(12)]

119. If SN-05 is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(a)(13)]

120. The permittee shall report, for SN-05, each instance in which each applicable emission limit and operating limit in Tables 2 through 4 to 40 C.F.R. § 63 Subpart DDDDD, is not met. These instances are deviations from the operating limits of Subpart DDDDD. These deviations must be reported in accordance with the requirements of § 63.7550. [8 CAR § 41-204 and 40 C.F.R. § 63.7540(b)]

121. The permittee shall submit to the Administrator, for SN-05, all of the notifications in 40 C.F.R. §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to SN-05 by the dates specified. [8 CAR § 41-204 and 40 C.F.R. § 63.7545(a)]

122. The permittee shall submit, for SN-05, a notification of intent to conduct a performance test at least 60 days before the performance test is scheduled to being. [8 CAR § 41-204 and 40 C.F.R. § 63.7545(d)]

123. If the permittee is required to conduct an initial compliance demonstration, for SN-05, as specified in 40 C.F.R. § 63.7530, then a Notification of Compliance Status (NCS) must be submitted according to § 63.9(h)(2)(ii). The NCS shall contain the information identified in §§ 63.7545(e)(1) through (8), as applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.7545(e)]

124. The permittee must submit, for SN-05, each applicable report identified in Table 9 to 40 C.F.R. § 63 Subpart DDDDD. Each report shall be submitted in accordance with 40 C.F.R. § 63.7550(b). [8 CAR § 41-204 and 40 C.F.R. §§ 63.7550(a) and (b)]

125. Each compliance report for SN-05 must contain the information outlined in 40 C.F.R. § 63.7550(c), as applicable depending on how the permittee chooses to comply with the limits set in 40 C.F.R. § 63 Subpart DDDDD. Deviations shall be reported in accordance with §§ 63.7550(d) and (e). [8 CAR § 41-204 and 40 C.F.R. §§ 63.7550(c), (d), and (e)]

126. All reports required by Table 9 of Subpart DDDDD shall be submitted in accordance with the provisions of 40 C.F.R. §§ 63.7550(h)(1) through (3), as applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.7550(h)]

127. The permittee shall keep records according to paragraphs (a)(1) and (a)(2) of 40 C.F.R. § 63.7555. These records shall include: [8 CAR § 41-204 and 40 C.F.R. § 63.7555(a)]

    a. A copy of each notification and report that was submitted to comply with 40 C.F.R. § 63 Subpart DDDDD, including all documentation supporting any initial notification or notification of compliance status or semiannual compliance report that was submitted according to the requirements in § 63.10(b)(2)(xiv). [8 CAR § 41-204 and 40 C.F.R. § 63.7555(a)(1)]

    b. Records of performance tests, fuel analyses, and other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii) [8 CAR § 41-204 and 40 C.F.R. § 63.7555(a)(2)]

    c. For each CEMS, COMS, and continuous monitoring system, the permittee must keep records according to 40 C.F.R. §§ 63.7555(b)(1) through (5). [8 CAR § 41-204 and 40 C.F.R. § 63.7555(b)]

    d. Records required in Table 8 to Subpart DDDDD, as applicable, to show continuous compliance with each emission limit and operating limit. [8 CAR § 41-204 and 40 C.F.R. § 63.7555(c)]

    e. Applicable records as listed in §§ 63.7555(d)(1) through (11). [8 CAR § 41-204 and 40 C.F.R. § 63.7555(d)]

f. Records of the calendar date, time, occurrence, and duration of each startup and shutdown. [8 CAR § 41-204 and 40 C.F.R. § 63.7555(i)]

g. Records of the type(s) and amount(s) of fuels used during each startup and shutdown. [8 CAR § 41-204 and 40 C.F.R. § 63.7555(j)]

128. The permittee shall maintain all records required by 40 C.F.R. § 63 Subpart DDDDD in a form suitable and readily available for expeditious review, according to § 63.10(b)(1). Each record must be kept for five (5) years following the date of each occurrence, measurement, maintenance, corrective action, or record. Each record must be kept on-site or they must be accessible from on-site (for example, through a computer network), for at least two (2) years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). The records main be kept off-site for the remaining three (3) years. [8 CAR § 41-204 and 40 C.F.R. § 63.7560]

129. The permittee shall comply with the applicable provisions of the General Provisions in 40 C.F.R. §§ 63.1 through 63.15 as outlined in Table 10 to 40 C.F.R. § 63 Subpart DDDDD. [8 CAR § 41-204 and 40 C.F.R. § 63.7565]

SN-03, SN-06A, SN-06B, and SN-06C
Rail Car Rotary Dumper and Handling/Conveying Emissions

Source Description

SN-03, the coal for the White Bluff Steam Electric Station is received by rail. Each rail car is equipped with rotary couplings which enable the rail car rotary dumper to grasp one car at a time and empty it without removing the car from the train. The rail car rotary dumper, SN-03 (M1), is capable of emptying approximately 30 cars per hour. Emissions from the rail car rotary dumper are regulated under the State Implementation Plan (SIP), 8 CAR pt. 41.

SN-06, minor emission sources at the plant include coal handling/conveying operations (not subject to NSPS Subpart Y). For this permitting action, SN-06 was separated into three sources: SN-06A, SN-06B, and SN-06C. SN-06A includes those emission points that were previously permitted as controlled with Amerclones, rotoclones, and water sprays. These emissions are now controlled with enclosures and a dust collector. This includes emission points M2, M3, M5, M6, M7, M8, M9, M16, M24, M25, M26, M27, and M28. SN-06B includes those emission points associated with the stacker reclaimer. This includes emission points M17, M18, M20, M21, M22, and M23. SN-06C includes the emissions associated with the storage piles, haul roads, and ash landfill. This includes emission points M4, M11, M19, M34, M35, and M36. The following emission points were removed from the permit since these emission points no longer exist at the White Bluff facility: M10 and M33. The following emission points were removed from the permit as sources of emissions since they are inoperable: M12, M13, and M14. The M15 Dead Storage Vault was removed from the permit as a source of emissions since it is completely enclosed, underground, and the rotoclone dust collector connected to it is inoperable. This rotoclone will be removed or abandoned in place. M32 was removed from the permit since it has been removed from service.

Specific Conditions

130. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
03	Rail Car Rotary Dumper	PM_{10} VOC	0.1 1.3	0.1 -
06A	Handling/ Conveying Emissions	PM_{10} VOC	0.4 0.3	1.6 -
03 06A	Rail Car Rotary Dumper and Handling/ Conveying VOC Emissions	VOC	-	2.2
06B	Stacker/Reclaimer Emissions	PM_{10}	0.5	2.1
06C	Storage Piles/Haul Road Emissions	PM_{10}	41.1	95.0
		VOC	27.4	5.0

131. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
03	Rail Car Rotary Dumper	PM	0.1	0.1
06A	Handling/Conveying Emissions	PM	0.8	3.4
06B	Stacker/Reclaimer Emissions	PM	1.0	4.3
06C	Storage Piles/Haul Road Emissions	PM	143.6	280.4

132. The permittee shall not cause to be discharged to the atmosphere any emissions which exhibit an opacity greater than 20 percent from SN-03. The opacity shall be measured in accordance with EPA Reference Method 9. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]

133. The permittee shall use water and/or non-hazardous chemical sprays while the dumper is operating at SN-03, except when the ambient temperature is below 40 degrees F or while it is raining. Compliance with this condition shall represent compliance with this source's applicable requirements. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

134. Weekly observations of the opacity from source SN-06A shall be conducted by personnel familiar with the permittee's visible emissions. The permittee shall maintain personnel trained in (but not necessarily certified in) EPA Reference Method 9. If visible emissions from any of the towers, enclosed conveyors, or silos are detected, the permittee shall take action to identify the cause of the visible emissions, implement corrective action, and document if visible emissions were present following the corrective action. If visible emissions are still present following the corrective action, the permittee shall document that visible emissions do not appear to be in excess of 20% opacity and shall document that visible emissions did not cause a nuisance off-site. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this condition. These records shall be updated weekly, kept on site, and made available to Division personnel upon request. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]

    a. The date and time of the observation.

    b. If visible emissions were detected.

c. If visible emissions were detected, the cause of the visible emissions, the corrective action taken, and if the visible emissions were present following the corrective action.

d. If visible emissions were present following the corrective action, document that the visible emissions do not appear to be in excess of 20% opacity and document that the visible emissions do not cause a nuisance off-site.

e. The name of the person conducting the opacity observations.

135. The permittee shall conduct weekly observations of the opacity for the following source: SN-06B. Weekly observations from source SN-06B shall be conducted by personnel familiar with the permittee's visible emissions. The permittee shall maintain personnel trained in (but not necessarily certified in) EPA Reference Method 9. If visible emissions from stackout, reclaiming, or any of the belts or transfer points are detected, the permittee shall take action to identify the cause of the visible emissions, implement corrective action, and document if visible emissions were present following the corrective action. If visible emissions are still present following the corrective action, the permittee shall document that visible emissions do not cause a nuisance beyond the property boundary. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this condition. These records shall be updated weekly, kept on site, and made available to Division personnel upon request. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

a. The date and time of the observation.

b. If visible emissions were detected.

c. If visible emissions were detected, the cause of the visible emissions, the corrective action taken, and if the visible emissions were present after the corrective action was taken.

d. If visible emissions were present following the corrective action, document that the visible emissions do not cause a nuisance beyond the property boundary.

e. The name of the person conducting the opacity observations.

136. The permittee shall not operate in a manner such that fugitive emissions from the storage piles, pile operations (such as operation of mobile equipment upon the storage pile), and haul road (SN-06C) would cause a nuisance off-site. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. The permittee shall use water sprays or other techniques as necessary to control fugitive emissions. [8 CAR

§ 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

137. The VOC content of the dust suppressant chemical foam spray used at SN-03 and SN-06A shall not exceed 0.12 lb VOC/gal. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. 70.6]

138. The permittee shall maintain Material Safety Data Sheets which demonstrate compliance with Specific Condition #137. [8 CAR § 41-605 and 40 C.F.R. § 52, Subpart E]

139. The dust suppressant chemical foam spray used at SN-03 and SN-06A shall not contain any hazardous air pollutants. A material shall qualify as containing no HAPs if the Safety Data Sheet (SDS) for the product does not indicate any numeric HAP content. [8 CAR § 40-904 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

140. The permittee shall maintain Material Safety Data Sheets which demonstrate compliance with Specific Condition #139. [8 CAR § 40-904 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

141. Emissions of VOC from the usage of the dust suppressant chemical foam spray at SN-03 and SN-06A shall not exceed 2.2 tons of VOC per consecutive 12 month period. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

142. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #141. These records shall be updated no later than the last day of the month following the month to which the records pertain. Twelve month rolling totals and each individual month's data shall be kept on site, and shall be made available to Division personnel upon request. The twelve month rolling totals and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

143. The permittee shall comply with the maintenance plan submitted to the Division for the rotary car dumper. The requirements shall include, but are not limited to, the inspection of the spray nozzles for pluggage. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

144. The permittee shall not operate the following emission sources: M12 Dead Storage Hopper 4A, M13 Dead Storage Hopper 3A, and M14 Dead Storage Hopper 2A. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

145. The permittee shall use the foam sprays while the dumper (SN-03) is in operation except when the ambient temperature is below 40 degrees F or while it is raining. [8 CAR § 41-

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

146. Total traffic associated with activated carbon deliveries, halide solution deliveries, and fly ash trucks hauling ash to the on-site landfill shall not exceed 63,586 vehicle miles traveled per consecutive twelve (12) month period on paved roads and 21,507 vehicle miles traveled per consecutive twelve (12) month period on unpaved roads. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

147. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #146. Compliance shall be demonstrated by recording the number of deliveries of activated carbon, the number of deliveries of halide solution, and the tons of fly ash disposed of in the on-site landfill. The monthly mileage traveled shall be calculated based on the following equations:

Monthly Total Paved Miles Traveled = (AC * DPAC) + (HLD * DPHLD) + ((TASH/26) * DPASH)

Monthly Total Unpaved Miles Traveled = (AC * DUPAC) + (HLD * DUPHLD) + ((TASH/26) * DUPASH)

Where:

AC = monthly number of activated carbon deliveries
DPAC = round trip distance over paved roads for activated carbon deliveries
HLD = monthly number of halide solution deliveries
DPHLD = round trip distance over paved roads for halide solution deliveries
TASH = monthly tons of fly ash disposed in the on-site landfill
DPASH = round trip distance over paved roads for fly ash landfill disposal
DUPAC = round trip distance over unpaved roads for activated carbon deliveries
DUPHLD = round trip distance over unpaved roads for halide solution deliveries
DUPASH = round trip distance over unpaved roads for fly ash landfill disposal

The round trip mileage for activated carbon deliveries, halide solution deliveries, and for ash truck trips to the on-site landfill will be checked annually to determine the number of miles on paved and unpaved road. This check will be completed prior to the end of the first quarter of the year. The results will be recorded and used in the calculation for the remainder of the year unless an additional check is performed. The total miles traveled records shall be updated no later than the last day of the month following the month which the records represent. The records shall be kept on site, and shall be provided to Division personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

148. The permittee shall not operate the four Coal Yard Dozers more than a combined 12,000 hours per consecutive twelve (12) month period, and the water wagon shall not exceed 4,000 hours per consecutive twelve (12) month period. Hours of operation do not include time spent idling while stationary. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

149. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #148. These records shall be updated no later than the last day of the month following the month which the records represent. The records shall be kept on site, and shall be provided to Division personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

150. The cat scraper shall not exceed 1,500 hours of operation per consecutive twelve (12) month period. Hours of operation do not include time spent idling while stationary. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

151. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #150. These records shall be updated no later than the last day of the month following the month which the records represent. The records shall be kept on site, and shall be provided to Division personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

152. The permittee shall not apply, at SN-06C, more than 10,000 gallons of dust suppressant that contains VOC per any consecutive twelve month period. The permittee shall not use any dust suppressant at SN-06C that exceeds a concentration of more than 1.0 lb VOC per gallon. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

153. The permittee shall maintain records which demonstrate compliance with Specific Condition #152. These records shall include documentation that identifies the dust suppressant used, the composition, and the amount of dust suppressant(s) used each month. These records shall be updated no later than the last day of the month following the month which the records represent. The records shall be kept on site, and shall be provided to Division personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

SN-04
Fly Ash Silos (2) with fabric filters

Source Description

The White Bluff Steam Electric Station is equipped with two (2) fly ash silos. Particulate emissions from the silos are controlled by fabric filters, SN-04, with a control efficiency of 99.9% for PM and 99.8% for PM_{10}.

Specific Conditions

154. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
04 (M30-M31)	Fly Ash Silos (2) with Fabric Filters	PM_{10}	0.1	0.1

155. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
04 (M30-M31)	Fly Ash Silos (2) with Fabric Filters	PM	0.1	0.1

156. The permittee shall not cause to be discharged to the atmosphere any emissions which exhibit an opacity greater than 20 percent. The opacity shall be measured in accordance with EPA Reference Method 9. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]

157. Plant personnel will perform a daily visual check, when either SN-01 or SN-02 is in operation during daylight hours, to ensure the baghouse is functioning properly. Observations of the opacity from source SN-04 shall be conducted by personnel familiar with the permittee's visible emissions. These observations of opacity shall be conducted weekly and whenever visible emissions are detected during the daily visual checks. The permittee shall maintain personnel trained in (but not necessarily certified in) EPA Reference Method 9. If visible emissions are detected, the permittee shall identify the cause of the visible emissions and implement corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this condition. These records shall be updated daily, kept on site, and made available to Division personnel upon request. The records shall be submitted to the Division in accordance with General Provision #7. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

a. The date and time of the opacity observation and/or visual check.

b. If any visible emissions were detected.

c. If any visible emissions were detected, the permittee shall document the opacity, the cause of the visible emissions, the corrective action taken, any necessary repairs, and if any visible emissions were detected following the repairs.

d. The name of the person conducting the opacity observation and/or visual check.

158. The permittee shall comply with the maintenance plan submitted to the Division for the fly ash silos (See Appendix C). Requirements include but are not limited to the following: [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

a. Check air leaks on pulsation system;

b. Check air operated valves;

c. Check piping and supports;

d. Check air cylinders;

e. Check baghouse doors and seals;

f. Check diffuser blower bearings for heat and vibration;

g. Check bags;

h. Check blower case for excessive heat buildup; and

i. Check inlet filter and change as needed.

159. The permittee shall conduct semi-annual maintenance inspections on the baghouses at SN-04. These inspections shall include checking all of the requirements listed in Specific Condition #158. The permittee shall maintain a record of these inspections. This record shall be kept on site and made available to Division personnel upon request. [8 CAR § 41-605 and 40 C.F.R. §§ 52 Subpart E and 64]

SN-07
Fuel Oil Storage Tank

Source Description

No. 2 fuel oil is stored in a storage tank (SN-07) on site. The tank has a capacity of 3,360,000 gallons or 80,000 barrels. The tank is cylindrical with a fixed roof.

Specific Conditions

160. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
07	Fuel Oil Tank	VOC	1.7	1.9

161. The permittee shall not exceed the annual throughput limit of 112,000,000 gallons of No. 2 fuel oil at SN-07 during any consecutive twelve month period. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

162. The permittee shall maintain records which demonstrate compliance with the limit set forth in Specific Condition #161. These records may be used by the Division for enforcement purposes. These records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Division personnel upon request. The twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

SN-25
Miscellaneous Storage Tanks

Source Description

The White Bluff Steam Electric Station has numerous storage tanks which store fuel oil and gasoline, most of which are Insignificant Activities. SN-25 is a 1,000 gallon gasoline storage tank. Emissions from the gasoline storage tank are VOC and HAPs.

Specific Conditions

163. 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 #165 and #166. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
25	Misc Storage Tank (Gasoline, 1000 gal)	VOC	11.7	0.4

164. 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 #165 and #166. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
25	Misc Storage Tank (Gasoline, 1000 gal)	Total HAPs	0.67	0.02

165. The permittee shall store gasoline only in storage tank SN-25. Supporting documentation shall be maintained on site to demonstrate compliance with this specific condition. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

166. The permittee shall not exceed the annual throughput limit of 16,000 gallons of fuel at SN-25 during any consecutive twelve month period. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

167. The permittee shall maintain records which demonstrate compliance with the limits set forth in the Specific Conditions #165 and #166. These records may be used by the Division for enforcement purposes. These records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Division personnel upon request. The

twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

168. RESERVED

169. RESERVED

SN-17 and SN-18
Cooling Towers

Source Description

The White Bluff Steam Electric Station operates two (2) cooling towers for the purpose of waste heat dissipation. The cooling towers obtain makeup water from the Arkansas River and from the capture of site drainage.

Specific Conditions

170. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
17 (X24)	Cooling Tower	PM_{10}	4.6	19.9
18 (X25)	Cooling Tower	PM_{10}	4.6	19.9

171. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
17 (X24)	Cooling Tower	PM	4.6	19.9
18 (X25)	Cooling Tower	PM	4.6	19.9

172. The permittee shall not cause to be discharged to the atmosphere from these sources any emissions which exhibit an opacity greater than 20 percent. The opacity shall be measured in accordance with EPA Reference Method 9. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]

173. Total dissolved solids shall not exceed 2,800 parts per million. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

174. The permittee shall monitor the total dissolved solids weekly when the unit is operating to demonstrate compliance with Specific Condition #173. The permittee shall maintain records that demonstrate compliance with this specific condition. These records shall be updated weekly, kept on site, and made available to Division personnel upon request. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

175. The circulating water flow for SN-17 and SN-18 shall not exceed 22,125 kgal/hr per tower. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

176. The permittee shall verify the circulating water flow every three years to demonstrate compliance with Specific Condition #175. The flow rate for each cooling tower shall be measured by a dye dilution test, properly calibrated follow meters, or other equivalent flow measurement method. The permittee shall maintain records that demonstrate compliance with this specific condition. These records shall be updated following each flow verification, kept on site, and made available to Division personnel upon request. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

SN-19
Coal Barging and Transfer

Source Description

This source consists of six transfer points and a paved/unpaved haul road for hauling the delivered coal via truck from the barge to the on-site coal storage piles. The six transfer points include: the conveyor feeder hopper which is filled from the barge with a large trackhoe, the drop point from the conveyor feed hopper to the first conveyor, the drop point from the first conveyor to the second conveyor, the truck feed hopper when filled via the second conveyor, filling of trucks from the truck feed hopper, and dumping the trucks onto the coal storage piles. The haul road consists of 1.9 miles of paved road and 0.25 miles of unpaved road. The unpaved road will be controlled with chemical suppressant and the paved road will be controlled by wetting and sweeping.

Specific Conditions

177. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
19	Coal Barging and Transfer	PM_{10}	2.5	6.1

178. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
19	Coal Barging and Transfer	PM	9.8	24.2

179. The permittee shall not operate in a manner such that emissions from the haul roads and transfer points (SN-19) would cause a nuisance off-site. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. The permittee shall use water sprays, sweeping, or other techniques as necessary to control emissions. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

180. The permittee shall not exceed the annual throughput limit of 2,733,120 tons of coal at SN-19 during any consecutive twelve month period to demonstrate compliance with the annual emissions from the six transfer points. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

181. The permittee shall maintain purchase records which demonstrate compliance with Specific Condition #180. These records may be used by the Division for enforcement purposes. These records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Division personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

182. The silt loading for the paved roads shall not exceed 0.99 g/m^2. Silt testing was conducted on October 5, 2005. Documentation of this test shall be maintained on site. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

183. The silt fraction for the unpaved roads shall not exceed 6.8%. Silt testing was conducted on September 22, 2005. Documentation of this test shall be maintained on site. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

184. The permittee shall not exceed 259,019.4 vehicle miles traveled per consecutive twelve (12) month period on the paved roads at SN-19. The permittee shall not exceed 34,081.5 vehicle miles traveled per consecutive twelve (12) month period on the unpaved roads at SN-19. This condition is necessary to demonstrate compliance with the haul road emission limits. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

185. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #184. Compliance shall be demonstrated by recording the round trips traveled by the dust control equipment (water trucks, sweepers, etc.), recording the tons of barge delivered coal unloaded, and calculating the vehicle miles traveled based on the following equations:

$$\text{Monthly Total Paved Miles Traveled} = \left[\left(\text{Control Equipment Round Trips}\right) + \left(\frac{\text{Monthly tons unloaded}}{\text{26 tons per round trip}} \right) \right] \times \left(\text{"Miles Paved" per round trip}\right)$$

$$\text{Monthly Total Unpaved Miles Traveled} = \left[\left(\text{Control Equipment Round Trips}\right) + \left(\frac{\text{Monthly tons unloaded}}{\text{26 tons per round trip}} \right) \right] \times \left(\text{"Miles Unpaved" per round trip}\right)$$

Haul truck weight shall typically be 40 tons loaded and 14 tons unloaded, and generally only full haul trucks shall be used to transport coal. The round trip mileage will be 3.8 miles paved and 0.5 miles unpaved unless an alternate shorter route is implemented. If an alternate route is to be used the round trip mileage will be checked and submitted to the Division. The new mileage can be used in the calculations immediately upon approval by the Division. The total miles traveled records shall be updated no later than the last day of the month following the month which the records represent. The records shall be kept on site, and shall be provided to Division personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance

with General Provision #7. Construction of an alternate haul road shall comply with Plantwide Conditions #1 and #2. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

186. The permittee shall comply with the Haul Road Dust Control Plan for the Barge Unloading Operation (Appendix D). This plan shall be kept on site, and shall be provided to Division personnel upon request. The paved roads shall be controlled by wetting and sweeping. The unpaved roads shall be controlled by the application of a chemical dust suppressant. Control shall be required more frequently as necessary to comply with Specific Condition #179. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

187. The chemical suppressant used on the unpaved roads at SN-19 shall not contain any VOCs. The permittee shall maintain the MSDS on site to demonstrate compliance with this specific condition. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

188. The chemical suppressant used on the unpaved roads at SN-19 shall not contain any HAPs. The permittee shall maintain the MSDS on site to demonstrate compliance with this specific condition. [8 CAR § 40-904 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN-20
Degreasing Operations

Source Description

This source consists of eight degreasers with a total capacity of 605 gallons. Four (4) of the degreasers are used during outage periods only.

Specific Conditions

189. The permittee shall not exceed the emission rates set forth in the following table. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
20	Degreasing Operations	VOC	6.8	13.6

190. The VOC content of the solvent used at SN-20 shall not exceed 6.8 pounds of VOC per gallon of solvent. Material Safety Data Sheets shall be maintained on site to demonstrate compliance with this specific condition. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

191. The throughput of SN-20 shall not exceed 4,000 gallons of solvent per consecutive twelve-month period. The permittee may track this solvent throughput either through usage records alone, or through a combination of solvent purchase records and solvent disposal records, where the permittee maintains documentation that any spent solvent was removed from the site and sent off-site for disposal or recycling. If purchase and disposal records are utilized to track throughput, the permittee shall calculate throughput as the difference between the amount of solvent purchased and added to the degreaser minus the amount of solvent shipped off-site for disposal or recycling. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

192. Monthly records shall be maintained to demonstrate compliance with Specific Condition #191. These records shall be updated no later than the last day of the month following the month which the records represent. A twelve-month rolling total and each individual month's data shall be maintained on site, made available to Division personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

SN-21 and SN-22
Emergency Diesel Generator and Emergency Diesel Fire Pump

Source Description

An 8.22 MMBtu/hr emergency diesel generator and a 365 HP Cummins, Model CFP9E-F30 diesel fire pump are used for emergency situation.

Specific Conditions

193. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by purchasing a NSPS certified engine and by Specific Condition #196. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
21	Emergency Diesel Generator	PM_{10}	0.5	0.6
		SO_2	4.2	4.5
		VOC	0.8	0.8
		CO	7.0	7.6
		NO_x	26.4	28.5
22	Emergency Diesel Fire Pump	PM_{10}	0.2	0.2
		SO_2	0.8	1.2
		VOC	1.0	1.4
		CO	2.1	3.2
		NO_x	2.5	3.7

194. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by purchasing a NSPS certified engine and by Specific Condition #196. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
21	Emergency Diesel Generator	PM	0.6	0.6
		Total HAPs	0.02	0.02
22	Fire Pump Emergency Diesel Generator	PM	0.2	0.2
		Total HAPs	0.02	0.02

195. The permittee shall not exceed 20% opacity from SN-21 and SN-22 as measured by EPA Reference Method 9. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #198. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]

196. The permittee shall not operate the emergency diesel generator (SN-21) in excess of 2,160 hours and the fire pump emergency diesel generator (SN-22) in excess of 3,000 hours per calendar year. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

197. The permittee shall maintain records of the hours of operation of SN-21 and SN-22 which demonstrate compliance with limits set in Specific Condition # 196. These records shall be updated on a monthly basis, and shall be provided to Division personnel upon request. An annual total and each individual month's data shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

198. Daily visible emission observations shall be used as a method of compliance verification for the opacity limits assigned for SN-21 and SN-22 while the emergency diesel generator (SN-21) or emergency diesel fire pump (SN-22) is in operation for more than 24 consecutive hours. The observations shall be conducted by someone familiar with EPA Reference Method 9. If during the observations, visible emissions are detected which appear to be in excess of the permitted opacity limit, the permittee shall:

    a. Take immediate action to identify the cause of the visible emissions,

    b. Implement corrective action, and

    c. If excessive visible emissions are still detected, an opacity reading shall be conducted in accordance with EPA Reference Method 9 for point sources and in accordance with EPA Method 22 for non-point sources. This reading shall be conducted by a person trained and certified in the reference method. If the opacity reading exceeds the permitted limit, further corrective measures shall be taken.

    d. If no excessive visible emissions are detected, the incident shall be noted in the records as described below.

    e. The permittee shall maintain records related to all visible emission observations and Method 9 readings. These records shall be updated on an as-performed basis. These records shall be kept on site and made available to Division personnel upon request. These records shall contain:

        i. The time and date of each observation/reading,

        ii. Any observance of visible emissions appearing to be above permitted limits or any Method 9 reading which indicates exceedance,

        iii. The cause of any observed exceedance of opacity limits, corrective actions taken, and results of the reassessment, and

iv. The name of the person conducting the observation/reading.

199. The permittee shall conduct an opacity reading using Method 9 at SN-21 and SN-22 at least once a year when it is operating. The permittee shall maintain records which demonstrate compliance with the opacity limit. These records may be used by the Division for enforcement purposes. The records shall be provided to the Division personnel upon request. [8 CAR § 41-403, 8 CAR § 41-605 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

200. SN-21 is subject to 40 C.F.R., § 63 Subpart ZZZZ, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.* This engine is subject to the requirements in 40 C.F.R. 63.6640(f). No other requirements apply. [8 CAR § 41-204 and 40 C.F.R. § 63.6640(f)]

a. If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines. 63.6640(f)
b. There is no time limit on the use of emergency stationary RICE in emergency situations. 63.6640(f)(1)
c. You may operate your emergency stationary RICE for the purpose specified in paragraph (f)(2)(i) of 63.6640 for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of 63.6640 counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).
    i. Emergency stationary RICE 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 RICE beyond 100 hours per calendar year.
d. Emergency stationary RICE located at major sources of HAP 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 provided in paragraph (f)(2) of 63.6640. 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 supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. 63.6640(f)(3)

201. SN-22 is a new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions. SN-22 must meet the requirements of 40 C.F.R. § 63 Subpart ZZZZ by meeting the requirements of 40 C.F.R. § 60 subpart IIII, for compression ignition engines. No further requirements apply for this engine under this part. [8 CAR § 41-204 and 40 C.F.R. § 63.6590(c)(6)]

202. 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 of 40 C.F.R. § 60 Subpart IIII, for all pollutants. Compliance is determined by purchase of a certified engine. [8 CAR § 41-204 and 40 C.F.R. § 60.4205(c)]

Table 4 to Subpart IIII of § 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
225≤KW<450 (300≤HP<600)	2009+	4.0 (3.0)		0.20 (0.15)

203. 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 C.F.R. §1090.305 below for nonroad diesel fuel on a per-gallon standard. [8 CAR § 41-204, 40 C.F.R. §§ 60.4207(b), and 80.510(b)]

a. Sulfur content.

i. 15 ppm maximum for NR diesel fuel.

b. Cetane index or aromatic content, as follows:

i. A minimum cetane index of 40; or

ii. A maximum aromatic content of 35 volume percent.

204. If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine. [8 CAR § 41-204 and 40 C.F.R. § 60.4209(a)]

205. 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 C.F.R. § 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4210(f)]

206. 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 specifications. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(c)]

207. Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per calendar year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone 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. For owners and operators of emergency engines meeting standards under § 60.4205 but not § 60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(e)]

208. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4214(b)]

Table 5 to Subpart IIII of § 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

209. RESERVED

210. RESERVED

211. RESERVED

212. RESERVED

213. RESERVED

214. RESERVED

215. RESERVED

216. RESERVED

217. RESERVED

218. RESERVED

219. RESERVED

220. RESERVED

221. RESERVED

222. RESERVED

223. RESERVED

224. RESERVED

225. RESERVED

226. RESERVED

227. RESERVED

SN-24
Telecom Emergency Generator Engine

Source Description

SN-24 is a 64.1 Hp emergency generator powered by a propane-fired spark-ignition 4-stroke engine. It is used to provide back-up electrical power to a telecommunications tower in the event of a loss of power from the grid. This engine is fired only for periodic maintenance testing and to generate power in emergency situations.

Specific Conditions

228. 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 #230, #232, and #234. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
24	Telecom Emergency Generator Engine (Propane-fired)	PM_{10}	0.1	0.1
		SO_2	0.1	0.1
		VOC	1.5	0.4
		CO	54.7	13.7
		NO_x	1.5	0.4

229. 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 #230 and #232. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
24	Telecom Emergency Generator Engine (Propane-fired)	PM	0.1	0.1
		Total HAPs	0.04	0.01

230. The permittee shall not operate the emergency generator SN-24 in excess of 500 total hours (emergency and non-emergency) per calendar year 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 8 CAR § 41-502 and other applicable regulations. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

231. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #230. The permittee shall update these records by the fifteenth day of the

month following the month to which the records pertain. The calendar year totals and each individual month's data shall be maintained on-site, made available to Division personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

232. The permittee shall not exceed 5% opacity from SN-24 as measured by EPA Reference Method 9. Compliance for SN-24 shall be demonstrated by only combusting propane in the emergency generator. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

233. The telecom emergency generator engine (SN-24) is subject to and shall comply with all applicable requirements of 40 C.F.R. § 60 Subpart JJJJ—*Standards of Performance for Stationary Spark Ignition Internal Combustion Engines* and 40 C.F.R. § 63 Subpart ZZZZ—*National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*. Compliance with Subpart ZZZZ shall be demonstrated by compliance with Subpart JJJJ. The requirements of Subpart JJJJ include, but are not limited to, Specific Conditions #234 through #239. [8 CAR § 41-204 and 40 C.F.R. §§ 60.4230 and 63.6590(c)(1)]

234. SN-24 shall comply with the Phase I emission standards in 40 C.F.R. § 90.103, applicable to class II engines, over the entire life of the engine. These emission standards are listed in the table below. [8 CAR § 41-204, 40 C.F.R. §§ 60.4233(c), 60.4234, and 90.103]

Source	Emission Standards (g/kW-hr)	
	$HC+NO_X$	CO
SN-24	13.4	519

235. The permittee shall install a non-resettable hour meter upon startup of SN-24. [8 CAR § 41-204 and 40 C.F.R. § 60.4237(c)]

236. The permittee shall demonstrate compliance by purchasing an engine certified to the emission standards in §60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. In addition, the permittee shall operate and maintain SN-24 according to the manufacturer's emission-related instructions and keep records of conducted maintenance to demonstrate compliance. [8 CAR § 41-204 and 40 C.F.R. § 60.4243(a)]

237. The permittee shall operate SN-24 according to the requirements in § 60.4243(d)(1) through (3) as described below. [8 CAR § 41-204 and 40 C.F.R. § 60.4243(d)]

    a. There is no time limit on the use of emergency stationary ICE in emergency situations. [8 CAR § 41-204 and 40 C.F.R. § 60.4243(d)(1)]

b. The permittee may operate SN-24 for any combination of the purposes specified in paragraphs (d)(2)(i) through (iii) of §60.4243 for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of §60.4243 counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2). [8 CAR § 41-204 and 40 C.F.R. § 60.4243(d)(2)]

   i. SN-24 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4243(d)(2)(i)]

   ii. SN-24 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4243(d)(2)(ii)]

   iii. SN-24 may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. [8 CAR § 41-204 and 40 C.F.R. § 60.4243(d)(2)(iii)]

c. SN-24 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 (d)(2) of §60.4243. Except as provided in paragraph (d)(3)(i) of §60.4243, 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4243(d)(3)]

238. The permittee shall keep the following records for SN-24. [8 CAR § 41-204 and 40 C.F.R. § 60.4245(a)]

a. All notifications submitted to comply with 40 C.F.R. Part 60, Subpart JJJJ and all documentation supporting any notification. [8 CAR § 41-204 and 40 C.F.R. § 60.4245(a)(1)]

b. Maintenance conducted on the engine. [8 CAR § 41-204 and 40 C.F.R. § 60.4245(a)(2)]

c. Documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90, 1048, 1054, and 1060, as applicable. [8 CAR § 41-204 and 40 C.F.R. § 60.4245(a)(3)]

239. The permittee shall keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4245(b)]

240. Table 3 to 40 C.F.R. Part 60, Subpart JJJJ shows which parts of the General Provisions in §§60.1 through 60.19 apply to SN-24. [8 CAR § 41-204 and 40 C.F.R. § 60.4246]

SN-26
Combined Cycle Turbine

Source Description

The power generation equipment proposed for the JPS includes a Mitsubishi Model M501JAC CT equipped with supplementary-fired duct burners and an HRSG. To boost the output power and thermal efficiency of the gas turbine, the combustion air fed to the CT compressor can be saturated with water in an evaporative cooler at various times, predominantly during warm weather conditions. In addition to power from a generator turned by the gas turbine shaft, power is produced by a steam turbine generator which is fed steam generated in the HRSG. Final condensation of steam exiting the steam turbine is accomplished using air-cooled condensers.

At the 59°F design case, the JPS 1x1 combined cycle unit will have an efficient gross heat rate of 6,405 BTU/kWh-HHV, which equates to a relatively high net thermal efficiency of 51.6% (HHV basis). The maximum firing rates of the CT and duct burner are 4,114 MMBtu/hr-HHV and 863 MMBtu/hr-HHV, respectively, at a cold weather ambient temperature firing condition of 20°F.

Specific Conditions

241. 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 245 to 309. [8 CAR § 41-801 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
26	Combined Cycle Turbine – Normal Operation	PM	48.4	138.9
		PM_{10}	48.4	138.9
		$PM_{2.5}$	48.4	138.9
		SO_2	14.0	30.2
		VOC	10.7	402.8
		CO	24.8	1195.9
		NO_x	40.6	219.9
		SAM	21.38	46.17
		CO_2e	583,900	2,514,400
26	Combined Cycle Turbine – Startup/Shutdown Operations	PM	48.4	
		PM_{10}	48.4	
		$PM_{2.5}$	48.4	
		SO_2	14.0	
		VOC	2527.0	
		CO	7441.0	
		NO_x	294.0	
		SAM	21.38	
		CO_2e	377,600	

242. 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 249 and Plantwide Condition 5. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
26	Combined Cycle Turbine – All Operations	Total HAPs Ammonia	3.15 75.16	13.59 324.32

243. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with these emission limits shall be demonstrated by compliance with Specific Conditions 245 to 309. [8 CAR § 41-801, 8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

Source	Description	Pollutant	Control Technology	BACT Limit
SN-26	Combined Cycle Turbine	NO_X	Dry Low-NO_x Combustors and Selective Catalytic Reduction (SCR)	2.0 ppmvd @ 15% O_2 (3-hr avg) excluding startup, shutdown, and tuning 40.60 lb/hr during startup, shutdown, and tuning
		CO	Good Combustion Practices and Catalytic Oxidation	2.0 ppmvd @ 15% O_2 (3-hr avg) excluding startup, shutdown, and tuning 24.72 lb/hr during startup, shutdown, and tuning
		VOC	Good Combustion Practices and Catalytic Oxidation	1.5 ppmvd @ 15% O_2 (3-hr avg) excluding startup, shutdown, and tuning 10.62 lb/hr during startup, shutdown, and tuning
		PM_{10} $PM_{2.5}$ Opacity	Low Sulfur Pipeline Natural Gas, Good Combustion Practices	0.0097 lb/MMBtu (3-hr avg) Opacity 5%

Source	Description	Pollutant	Control Technology	BACT Limit
		SAM	Low Sulfur Pipeline Natural Gas	0.5 gr S/100 scf 21.38 lb/hr 46.17 TPY
		GHG	High-Efficiency Combined Cycle System, Low-Carbon Natural Gas Fuel	800 lb CO_2e/MWh gross (12-mo avg) prior to Jan 1, 2032 100 lb CO_2e/MWh gross (12-mo avg) after December 2031

244. The permittee shall not exceed 5% opacity from SN-26 as measured by EPA Reference Method 9. Compliance for SN-26 shall be demonstrated by only combusting natural gas in SN-26. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

245. The permittee shall initially test SN-26 for PM, PM_{10}, and $PM_{2.5}$ using EPA Test Methods 201A and 202.
    a. Testing shall be conducted during normal, steady-state operations.
    b. Testing shall use a 3-hour average.
    c. This test shall take place in accordance with Plantwide Condition #3.
    d. Testing shall be conducted with the source operating at least at 90% of its permitted capacity including duct burner. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate.
    e. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate.

    [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

246. The permittee shall initially, and thereafter, every five years, test SN-26 for VOC using EPA Test Method 25 or 25A.
    a. Testing shall be conducted during normal, steady-state operations.
    b. Testing shall use a 3-hour average.
    c. This test shall take place in accordance with Plantwide Condition #3.
    d. Testing shall be conducted with the source operating at least at 90% of its permitted capacity including duct burner. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate.

e. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate.
f. Testing shall also be conducted with the source operating at 65-75% of its permitted capacity including duct burner to demonstrate compliance with annual emission limits.

247. The permittee shall test SN-26 for Sulfuric Acid Mist (SAM) using EPA Test Method 8.
a. When using Test Method 8 to test for SO_2, the same testing shall be used to demonstrate compliance with both SO_2 and Sulfuric Acid Mist (SAM). See Condition #248.
b. Testing shall be conducted during normal, steady-state operations. To avoid interference from ammonia, testing may take place before SCR.
c. Testing shall use a 3-hour average.
d. This test shall take place in accordance with Plantwide Condition #3.
e. Testing shall be conducted with the source operating at least at 90% of its permitted capacity including duct burner Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate.
f. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate. [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

248. The permittee shall test SN-26 for SO_2 using EPA Test Method 8.
a. When using Test Method 8 to test initially for SO_2, concurrent testing shall be used to demonstrate compliance with SO_2 and Sulfuric Acid Mist (SAM).
b. Testing shall be conducted during normal, steady-state operations.
c. Testing shall use a 3-hour average.
d. This test shall take place in accordance with Plantwide Condition #3.
e. Testing shall be conducted with the source operating at least at 90% of its permitted capacity including duct burner Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate.
f. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate. [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

249. The permittee shall test ammonia emissions from SN-26 using EPA Reference Method 320, CTM-027, or other method approved by the Division. This test shall take place in accordance with Plantwide Condition #3. [8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

250. The permittee shall maintain the SCR catalyst inlet temperature and ammonia injection rate to ensure operation within the range specified by the catalyst manufacturer. [8 CAR § 40-904 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

251. The permittee shall record the SCR catalyst inlet temperature and ammonia injection rate once per day. These records shall be kept on site, in accordance with General Provision 7, and made available to Division personnel upon request. [8 CAR § 40-904 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

252. The permittee shall install a CEMs to monitor the emission rate of CO to show compliance with the CO emission limits in Specific Conditions 241 and 243. This monitor shall be operated in accordance with the Division's CEMs provisions attached as Appendix B to this Permit. [8 CAR § 41-603, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

253. To show compliance with the VOC limits for source SN-26 the permittee shall continuously monitor the CO emissions from the source and maintain them below the limits in Specific Condition 241 and 243. [8 CAR § 41-204 and 40 C.F.R. § 64]

254. The permittee shall submit reports as required by § 64.9(a). These records shall include: Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken; summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and a description of the actions taken to implement a QIP during the reporting period as specified in §64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring. [8 CAR § 41-204 and 40 C.F.R. § 64]

255. The permittee shall submit reports as required by § 64.9(b). The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions [8 CAR § 41-204 and 40 C.F.R. § 64]

NSPS Subpart KKKKa Conditions

256. For each stationary combustion turbine you must not discharge into the atmosphere from the affected facility any gases that contain an amount of NO_X that exceeds the applicable emissions standard and be in accordance with the requirements specified in paragraph (b) of 60.4320a. If you choose to use NO_X CEMS, input-based emission rates and standards are determined on a 4-operating-hour rolling basis. [8 CAR § 41-204 and 40 C.F.R. § 60.4320a(a)]

257. For all operations at ≥ 70% base load, the permittee shall not exceed a NOx flue gas concentration of 5 ppmvd at 15 percent O_2, or a NOx emission limit of either 7.9 ng/J (0.018 lb/MMBtu) on a heat input basis. For all operations at < 70% base load, the permittee shall not exceed a NO flue gas concentration of 96 ppmvd @ 15 percent O_2. [8 CAR § 41-204 and 40 C.F.R. § 60.4320a(b)(3)]

258. The NO_X emission standard that is applicable to your affected facility shall be determined on an operating-hour basis, unless you elect to use the alternative provided for in paragraph (b)(2) of 60.4320a. Determining the hourly NO_X emission standards for your affected facility requires recording hourly data and maintaining records according to the requirements in § 60.4390a. For hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponds to the highest emissions standard. For example, if your affected facility operates at 70 percent or less of its base load rating for any portion of the hour, the emission limit(s) in table 1 to this subpart for combustion turbines operating at 70 percent or less of base load rating shall apply for that hour. [8 CAR § 41-204 and 40 C.F.R. § 60.4320a(b)(1)]

259. You must meet the applicable NO_X emissions standard to your affected facility during all times that the affected facility is operating (including periods of startup, shutdown, and malfunction). [8 CAR § 41-204 and 40 C.F.R. § 60.4320a(d)]

260. Except as provided for in paragraphs (b) through (e) of 60.4330a, for each new, modified, or reconstructed stationary combustion turbine you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either: [8 CAR § 41-204 and 40 C.F.R. § 60.4330a(a)]
    a. 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output; or
    b. 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

261. You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction. [8 CAR § 41-204 and 40 C.F.R. § 60.4333a]

262. If you own or operate a stationary combustion turbine subject to a NO_X emissions standard in § 60.4320a, you must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400a or § 60.4405a. Thereafter, unless you perform continuous monitoring consistent with § 60.4335a, § 60.4340a, or § 60.4345a, you must conduct subsequent performance tests according to the applicable requirements in paragraphs (b)(1) through (6) of 60.4333a(b). [8 CAR § 41-204 and 40 C.F.R. §60.4333a(b)]

263. Except as provided for in paragraph (c)(1) or (2) of 60.4333a, for each stationary combustion turbine subject to a NO_X emissions standard in § 60.4320a, you must demonstrate continuous compliance using a continuous emissions monitoring system (CEMS) for measuring NO_X emissions according to the provisions in § 60.4345a. If your stationary combustion turbine is equipped with a NO_X CEMS, those measurements must be used to determine excess emissions. [8 CAR § 41-204 and 40 C.F.R. § 60.4333a(c)]

264. Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, maintain records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the initial and subsequent fuel combusted in your stationary combustion turbine at all times does not exceed applicable conditions specified in § 60.4370a; [8 CAR § 41-204 and 40 C.F.R. § 60.4333a(b)]

265. For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the fuel flow to the combustion turbine engine and any associated duct burners. [8 CAR § 41-204 and 40 C.F.R. § 60.4333a(e)]

266. Each CEMS measuring NO_X emissions used to meet the requirements of this subpart, must meet the requirements in paragraphs (a)(1) through (6) of 60.4345a. [8 CAR § 41-204 and 40 C.F.R. § 60.4345a]
    a. You must install, certify, maintain, and operate a NO_X monitor to determine the hourly average NO_X emissions in the units of the standard with which you are complying.
    b. If you elect to comply with an input-based or mass-based emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow monitor to continuously measure the heat input to the affected facility.

267. Each NO_X CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to 40 C.F.R. Part 60. The span value must be 125 percent of the highest applicable standard or highest anticipated hourly NO_X emissions rate. Alternatively, span values determined according to section 2.1.2 in appendix A to part 75 may be used. For stationary combustion turbines that do not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of Subpart

KKKKa, you may use NO_X and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to 40 C.F.R. Part 60 and the requirements of § 60.13, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. For stationary combustion turbines that use post-combustion technology to reduce emissions of NO_X to comply with the requirements of Subpart KKKKa, you may use NO_X and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to 40 C.F.R. Part 60. and the requirements of § 60.13 with approval from the Administrator or delegated authority, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. [8 CAR § 41-204 and 40 C.F.R. § 60.4345a(b)]

268. Each fuel flow meter must be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements in appendix D to part 75 of chapter 40 are acceptable for use under Subpart KKKKa. [8 CAR § 41-204 and 40 C.F.R. § 60.4345a(b)]

269. You must develop, submit to the Administrator or delegated authority for approval, maintain, and adhere to an on-site quality assurance (QA) plan for all of the continuous monitoring equipment you use to comply with this subpart. At a minimum, such a QA plan must address the requirements of § 60.13(d), (e), and (h). For the CEMS and fuel flow meters, the owner or operator of a stationary combustion turbine that does not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart may, with approval of the Administrator or delegated authority, satisfy the requirements of § 60.4345a(f) by implementing the QA program and plan described in section 1 in appendix B to part 75 of chapter 40 in lieu of the requirements in § 60.13(d)(1). [8 CAR § 41-204 and 40 C.F.R. § 60.4345a(f)]

270. At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating-day rolling average basis. [8 CAR § 41-204 and 40 C.F.R. §60.4345a(g)]

271. Determine NOx excess emissions under NSPS Subpart KKKKa using the procedures specified in 40 CFR 60.4350a(a) through (h). [8 CAR § 41-204 and 40 C.F.R. § 60.4350a]

272. If you elect to demonstrate compliance with a SO_2 emissions standard according to § 60.4333a(d)(3), you must maintain on-site records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the fuel combusted in your stationary combustion turbine at all times does not exceed the conditions specified in paragraph (b) through (e) of 60.4372a, as applicable to your stationary combustion turbine. [8 CAR § 41-204 and 40 C.F.R. § 60.4372a(a)]

273. Representative fuel sampling data following the procedures specified in section 2.3.1.4 or 2.3.2.4 in appendix D to part 75 of 40 C.F.R Chapter 40 documenting that the fuel meets the part 75 requirements to be considered either pipeline natural gas or natural gas. Your stationary combustion turbine may not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 110 ng SO_2/J (0.90 lb SO_2/MWh) gross energy output or 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. [8 CAR § 41-204 and 40 C.F.R. § 60.4372a(e)]

274. If your stationary combustion turbine is subject to the SO_2 emissions standard in § 60.4330a(a), then the fuel combusted must have a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) heat input or less. [8 CAR § 41-204 and 40 C.F.R. § 60.4372a(b)]

275. An owner or operator of a stationary combustion turbine that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, must submit reports of excess emissions and monitor downtime, according to § 60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction. [8 CAR § 41-204 and 40 C.F.R. § 60.4375a(a)]

276. The notification requirements of § 60.8 apply to the initial and subsequent performance tests. [8 CAR § 41-204 and 40 C.F.R. § 60.4375a(b)]

277. Within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a relative accuracy test audit (RATA), you must submit the results following the procedures specified in paragraph (g) of 60.4375a. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format. [8 CAR § 41-204 and 40 C.F.R. § 60.4375a(g)]

278. You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of 60.4375a. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. [8 CAR § 41-204 and 40 C.F.R. §60.4375a(f)]

279. If you are required to submit notifications or reports following the procedure specified in paragraph (g) of 60.4375a, you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in Subpart KKKKa, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of 60.4375a. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in paragraph (g) of of 60.4375a. [8 CAR § 41-204 and 40 C.F.R. § of 60.4375a(g)]

280. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation. [8 CAR § 41-204 and 40 C.F.R. § 60.4375a(j)]

281. For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (b)(1) and (2) of 60.4380a. [8 CAR § 41-204 and 40 C.F.R. § 60.4380a(b)]
    a. An excess emission that must be reported is any unit operating period in which the 4-operating-hour average NO_X emissions rate, 30-operating-day rolling average NO_X emissions rate, 4-hour mass-based emissions rate, or the 12-calendar-month mass-based emissions rate exceeds the applicable emissions standard in § 60.4320a as determined in § 60.4350a.
    b. A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: NO_X concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

282. If you choose the option to maintain records of the fuel sulfur content, excess emissions are defined as any period during which you combust a fuel that you do not have

appropriate fuel records or that fuel contains sulfur greater than the applicable standard. [8 CAR § 41-204 and 40 C.F.R. § 60.4385a]

283. You must maintain records of your information used to demonstrate compliance with this subpart as specified in § 60.7. [8 CAR § 41-204 and 40 C.F.R. § 60.4390a(a)]

284. Consistent with § 60.7(c), all reports required under § 60.7(c) must be electronically submitted via CEDRI by the 30th day following the end of each 6-month period. [8 CAR § 41-204 and 40 C.F.R. § 60.4395a]

285. If you use a CEMS the performance test must be performed according to the procedures specified in paragraph (b) of 60.4400a. [8 CAR § 41-204 and 40 C.F.R. § 60.4400a]
    a. The initial performance test must use the procedure specified in paragraphs (b)(1) through (4) of 60.4400a.
    b. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within ±25 percent of 100 percent of the base load rating while the source is combusting the fuel that is a normal primary fuel for that source. You may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. The ambient temperature must be greater than 0 °F during the RATA runs. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.
    c. For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) or the methodologies in appendix F to part 75, and for units complying with the output-based standard, measure the electrical and thermal output from the unit.
    d. Use the test data both to demonstrate compliance with the applicable NO_X emissions standard under § 60.4320a and to provide the required reference method data for the RATA of the CEMS described under § 60.4342a.
    e. Compliance with the applicable emissions standard in § 60.4320a is achieved if the sum of the NO_X emissions divided by the heat input (or gross or net energy output) for all the RATA runs, expressed in units of lb/MMBtu, ppm, lb/MWh, or kgs, does not exceed the emissions standard.

286. If you are an owner or operator of an affected facility complying with the fuel-based standard must submit fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) to satisfy the requirements of § 60.8. [8 CAR § 41-204 and 40 C.F.R. § 60.4415a]

NSPS Subpart TTTTa Conditions

287. For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard

specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of 60.5520a, as applicable. [8 CAR § 41-204 and 40 C.F.R. § 60.5520a(a)]

288. For SN-26, the permittee shall not exceed 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a. [8 CAR § 41-204 and 40 C.F.R. § 60.5520a]

289. For SN-26, the permittee shall not exceed 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a. [8 CAR § 41-204 and 40 C.F.R. § 60.5520a(a)]

290. Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to Subpart TTTTa that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of 60.5520a, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of 60.5520a. [8 CAR § 41-204 and 40 C.F.R. § 60.5520a(d)]
    a. Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

291. Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). [8 CAR § 41-204 and 40 C.F.R. §60.5525a(a)]

292. Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). [8 CAR § 41-204 and 40 C.F.R. § 60.5535a(a)]

293. accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to Subpart TTTTa as

required in § 60.5540a. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of § 60.5540a to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations. [8 CAR § 41-204 and 40 C.F.R. § 60.5540a(a)]

294. In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of § 60.5550a and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

295. You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to Subpart TTTTa). [8 CAR § 41-204 and 40 C.F.R. § 60.5540a]

296. You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs. [8 CAR § 41-204 and 40 C.F.R. § § 60.5550a]

297. For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of 40 C.F.R. Chapter 40. [8 CAR § 41-204 and 40 C.F.R. §§ 60.5550a(c)]

298. You must prepare and submit reports according to paragraphs (a) through (d) of § 60.5550a, as applicable [8 CAR § 41-204 and 40 C.F.R. § 60.5550a(a)]

299. You must submit all electronic reports required under paragraph (a) of § 60.5550a using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA. [8 CAR § 41-204 and 40 C.F.R. §§ 60.5550a(b)]

300. You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f). [8 CAR § 41-204 and 40 C.F.R. § 60.5560a(a)]

301. For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under 40 C.F.R. Chapter 75 Subpart F. [8 CAR § 41-204 and 40 C.F.R. § 60.5560a(b)]

302. You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for: [8 CAR § 41-204 and 40 C.F.R. § 60.5560a(c)]
    a. Each operating month (for all affected EGUs); and
    b. Each compliance period, including, each 12-operating-month compliance period.

303. Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month. [8 CAR § 41-204 and 40 C.F.R. § 60.5560a(d)]

304. You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period. [8 CAR § 41-204 and 40 C.F.R. § 60.5560a(e)]

305. You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart. [8 CAR § 41-204 and 40 C.F.R. § 60.5560a(f)]

306. For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory. [8 CAR § 41-204 and 40 C.F.R. § 60.5560a(h)]

307. Your records must be in a form suitable and readily available for expeditious review. [8 CAR § 41-204 and 40 C.F.R. § 60.5565a(a)]

308. You must maintain each record for 5 years after the date of conclusion of each compliance period. [8 CAR § 41-204 and 40 C.F.R. § 60.5565a(b)]

309. You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by Subpart TTTTa. [8 CAR § 41-204 and 40 C.F.R. § 60.5565a(c)]

SN-27 and 28
Turbine Facility Emergency Engines

Source Description

SN-27 is an emergency diesel-fired IC engine powers a 2,180-kW emergency standby generator. The engine is a Mitsubishi Model S16R-Y2PTAW2-1 with a 2,923-BHP rating.

SN-28, an emergency diesel-fired IC engine, powers a 235-kW emergency firewater pump. The engine is a John Deere Model 6068HFC48A with a 282 BHP rating.

Specific Conditions

310. 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 315, and 317 through 356. [8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
27	Emergency Standby Generator	PM	1.0	0.3
		PM_{10}	1.0	0.3
		$PM_{2.5}$	1.0	0.3
		SO_2	0.1	0.1
		VOC	2.7	0.7
		CO	16.9	4.3
		NO_x	30.8	7.7
		CO_2e	3,700	1,000
28	Emergency Diesel Fire Water Pump	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	1.9	0.5
		NO_x	2.1	0.6
		CO_2e	19.4	100

311. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions 315 and 316. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
27	Emergency Standby Generator	Total HAPs	0.04	0.01

SN	Description	Pollutant	lb/hr	tpy
28	Emergency Diesel Fire Water Pump	Total HAPs	0.01	0.01

312. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with these emission limits shall be demonstrated by compliance with Specific Conditions 315, and 317 through 356. [8 CAR § 41-801, 8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

Source	Description	Pollutant	Control Technology	BACT Limit
SN-27	Emergency Standby Generator	NO_X	Tier 2 USEPA-Certified NSPS Subpart IIII Engine, Good Combustion Practices	6.4 g/kWh
		CO	Tier 2 USEPA-Certified NSPS Subpart IIII Engine	3.5 g/kWh
		VOC	Tier 2 USEPA-Certified Engine, Manufacturer's Guarantee	0.56 g/kWh
		PM_{10} / $PM_{2.5}$	Tier 2 USEPA-Certified NSPS Subpart IIII Engine	0.20 g/kWh
		GHG	Efficient Tier 2 USEPA-Certified Engine, Good Combustion Practices	163 lb/MMBTU
SN-28	Emergency Diesel Fire Water Pump	NO_X	Tier 3 USEPA-Certified NSPS Subpart IIII Engine, Good Combustion Practices	4.0 g/kWh
		CO	Tier 3 USEPA-Certified NSPS Subpart IIII Engine	3.5 g/kWh
		VOC	Tier 3 USEPA-Certified Engine, Manufacturer's Guarantee	0.11 g/kWh

Source	Description	Pollutant	Control Technology	BACT Limit
		PM_{10} / $PM_{2.5}$	Tier 3 USEPA-Certified NSPS Subpart IIII Engine	0.20 g/kWh
		GHG	Efficient Tier 3 USEPA-Certified Engine, Good Combustion Practices	163 lb/MMBTU

313. The permittee shall not exceed 20% opacity from the Sources SN-27 and 28. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]

314. Annual observations of the opacity from Sources SN-27 and 28 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/perform an EPA Reference Method 9 test to verify emissions are not in excess of the permitted level. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated annually, kept on site, and made available to Division of Environmental Quality personnel upon request.
    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.

    [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

315. The permittee shall not operate any single emergency generator, SN-27 and 28 more than 500 hours in any consecutive 12-month period. The permittee shall maintain records of the hours of operation of the generator each month. These records shall be updated by the 15th day of the month following the month that the records represent, kept on site, made available to Division personnel upon request and in accordance with General Provision 7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

316. The permittee shall comply with the provisions of 40 C.F.R. Part 63 Subpart ZZZZ for SN-27 and 28 by complying with the provisions of 40 C.F.R. Part 60 Subpart IIII. [8 CAR § 41-204 and 40 C.F.R. § 63 Subpart ZZZZ]

40 C.F.R. § 60 Subpart IIII Conditions for Fire Pump Compression Ignition Engines
< 30 L/Cylinder (Constructed After 7-11-2005 and Manufactured After 7-1-2006)

317. SN-28 is subject to 40 C.F.R. § 60 Subpart IIII. The permittee shall comply with all applicable provisions of 40 C.F.R. § 60 Subpart IIII which includes, but is not limited to, Specific Conditions #318 through #333. [8 CAR § 41-204 and 40 C.F.R. § 60 Subpart IIII]

318. The permittee must comply with the emission standards in the table below for all pollutants. [8 CAR § 41-204 and 40 C.F.R. § 60.4205(c) and Table 4 to 40 C.F.R. § 60 Subpart IIII]

Maximum engine power	**Model year(s)**	**NMHC + NO_X g/KW-hr (g/HP-hr)**	**CO g/KW-hr (g/HP-hr)**	**PM g/KW-hr (g/HP-hr)**
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)

[3]In 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.

319. The permittee must operate and maintain stationary CI ICE that achieve the emission standards as required in § 60.4205 over the entire life of the engine. [8 CAR § 41-204 and 40 C.F.R. § 60.4206]

320. The permittee must use diesel fuel that meets the requirements of 40 C.F.R. § 80.510(b) for nonroad diesel fuel. [8 CAR § 41-204 and 40 C.F.R. § 60.4207(b)]

321. Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in § 60.4207. [8 CAR § 41-204 and 40 C.F.R. § 60.4207(e)]

322. 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 § 60.4208(a) through (g) after the dates specified in § 60.4208(a) through (g). [8 CAR § 41-204 and 40 C.F.R. § 60.4208(h)]

323. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4208(i)]

324. The permittee must install a non-resettable hour meter prior to startup of the engine. [8 CAR § 41-204 and 40 C.F.R. § 60.4209(a)]

325. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4209(b)]

326. If you are an owner or operator and must comply with the emission standards specified in 40 C.F.R. § 60 Subpart IIII, you must do all of the following, except as permitted under § 60.4211(g): [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)]
    a. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)(1)]
    b. Change only those emission-related settings that are permitted by the manufacturer; and [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)(2)]
    c. Meet the requirements of 40 C.F.R. §§ 89, 94 and/or 1068, as they apply to you. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)(3)]

327. 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 40 C.F.R. § 60 Subpart IIII and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in § 60.4211(b)(1) through (5). [8 CAR § 41-204 and 40 C.F.R. § 60.4211(b)]
    a. Purchasing an engine certified according to 40 C.F.R. § 89 or 40 C.F.R. § 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(b)(1)]
    b. 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 40 C.F.R. § 60 Subpart IIII and these methods must have been followed correctly. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(b)(2)]
    c. Keeping records of engine manufacturer data indicating compliance with the standards. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(b)(3)]
    d. Keeping records of control device vendor data indicating compliance with the standards. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(b)(4)]
    e. Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(b)(5)]

328. If you are an owner or operator of a CI fire pump engine the is manufactured during or after the model year that applies to your fire pump engine rating in table 3 to 40 C.F.R. § 60 Subpart IIII and must comply with the emission standards specified in § 60.4205(c), the permittee must demonstrate compliance by purchasing an engine certified to the emission standards in § 60.4205(c) for the same model year and NFPA nameplate engine power. The engine must be installed and configured according to the manufacturer's

emission-related specifications, except as permitted in § 60.4211(g). [8 CAR § 41-204 and 40 C.F.R. § 60.4211(c)]

329. The permittee must operate the emergency stationary ICE according to the requirements in § 60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 C.F.R. § 60 Subpart IIII, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in § 60.4211(f)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in § 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 C.F.R. § 60 Subpart IIII and must meet all requirements for non-emergency engines. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)]
    a. There is no time limit on the use of emergency stationary ICE in emergency situations. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(1)]
    b. The permittee may operate the emergency stationary ICE for any combination of the purposes specified in § 60.4211(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by § 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by § 60.4211(f)(2). [8 CAR § 41-204 and 40 C.F.R. § 60.4211(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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(2)(i)]
    c. 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 provided in § 60.4211(f)(2). Except as provided in § 60.4211(f)(3)(i), 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)]
        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: [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)]

1. The engine is dispatched by the local balancing authority or local transmission and distribution system operator; [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(A)]
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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(B)]
3. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(C)]
4. The power is provided only to the facility itself or to support the local transmission and distribution system. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(D)]
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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(E)]

330. 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: [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)]
    a. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)(1)]
    b. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)(2)]

c. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)(3)]

331. Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to 40 C.F.R. § 60 Subpart IIII must do so according to § 60.4212(a) through (e). [8 CAR § 41-204 and 40 C.F.R. § 60.4212]

332. The permittee is not required to submit an initial notification. Starting with the model years in the table below, 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4214(b) and Table 5 to 40 C.F.R. § 60 Subpart IIII]

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

333. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4214(c)]

334. Table 8 to 40 C.F.R. § 60 Subpart IIII shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you. [8 CAR § 41-204 and 40 C.F.R. § 60.4218]

40 C.F.R. § 60 Subpart IIII Conditions for Non-Fire Pump Emergency Compression Ignition Engines < 30 L/Cylinder (2007 Model Year and Later Constructed After 7-11-2005 and Manufactured After 4-1-2006)

335. SN-27 is subject to 40 C.F.R. § 60 Subpart IIII. The permittee shall comply with all applicable provisions of 40 C.F.R. § 60 Subpart IIII which includes, but is not limited to, Specific Conditions #336 through #352. [8 CAR § 41-204 and 40 C.F.R. § 60 Subpart IIII]

336. The provisions of 40 C.F.R. § 60 Subpart IIII are applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the stationary CI ICE are manufactured after April 1, 2006, and are not fire pump engines. For the purposes of 40 C.F.R. § 60 Subpart IIII, the date that construction commences is the date the engine is ordered by the owner or operator. [8 CAR § 41-204 and 40 C.F.R. § 60.4200(a)(2)(i)]

337. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4205(b)]

338. The permittee must operate and maintain stationary CI ICE that achieve the emission standards as required in § 60.4205 over the entire life of the engine. [8 CAR § 41-204 and 40 C.F.R. § 60.4206]

339. Beginning October 1, 2007, owners and operators of stationary CI ICE subject to 40 C.F.R. § 60 Subpart IIII that use diesel fuel must use diesel fuel that meets the requirements of 40 C.F.R. § 80.510(a). [8 CAR § 41-204 and 40 C.F.R. § 60.4207(a)]

340. Beginning October 1, 2010, owners and operators of stationary CI ICE subject to 40 C.F.R. § 60 Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 C.F.R. § 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4207(b)]

341. Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in § 60.4207. [8 CAR § 41-204 and 40 C.F.R. § 60.4207(e)]

342. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4208(a)]

343. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4208(b)]

344. 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 § 60.4208(a) through (g) after the dates specified in § 60.4208(a) through (g). [8 CAR § 41-204 and 40 C.F.R. § 60.4208(h)]

345. The requirements of § 60.4208 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4208(i)]

346. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4209(a)]

347. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4209(b)]

348. If you are an owner or operator and must comply with the emission standards specified in 40 C.F.R. § 60 Subpart IIII, you must do all of the following, except as permitted under § 60.4211(g): [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)]
    a. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)(1)]
    b. Change only those emission-related settings that are permitted by the manufacturer; and [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)(2)]
    c. Meet the requirements of 40 C.F.R. §§ 89, 94 and/or 1068, as they apply to you. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)(3)]

349. 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 40 C.F.R. § 60 Subpart IIII 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 § 60.4211(g). [8 CAR § 41-204 and 40 C.F.R. § 60.4211(c)]

350. If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in § 60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 C.F.R. § 60 Subpart IIII, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in § 60.4211(f)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in § 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 C.F.R. § 60 Subpart IIII and must meet all requirements for non-emergency engines. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)]
    a. There is no time limit on the use of emergency stationary ICE in emergency situations. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(1)]
    b. You may operate your emergency stationary ICE for any combination of the purposes specified in § 60.4211(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by § 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by § 60.4211 (f)(2). [8 CAR § 41-204 and 40 C.F.R. § 60.4211(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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(2)(i)]
    c. 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 provided in § 60.4211(f)(2). Except as provided in § 60.4211(f)(3)(i), 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)]
        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: [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)]

1. The engine is dispatched by the local balancing authority or local transmission and distribution system operator; [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(A)]
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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(B)]
3. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(C)]
4. The power is provided only to the facility itself or to support the local transmission and distribution system. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(D)]
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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(E)]

351. 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: [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)]
    a. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)(1)]
    b. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)(2)]

c. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)(3)]

352. The requirements for operators and prohibited acts specified in 40 C.F.R. § 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 C.F.R. § 1039.665. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(h)]

353. Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to 40 C.F.R. § 60 Subpart IIII must do so according to § 60.4212(a) through (e). [8 CAR § 41-204 and 40 C.F.R. § 60.4212]

354. The permittee is not required to submit an initial notification. Starting with the model years in the table below, 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4214(b) and Table 5 to 40 C.F.R. § 60 Subpart IIII]

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

355. 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. [8 CAR § 41-204 and 40 C.F.R. § 60.4214(c)]

356. Table 8 to 40 C.F.R. § 60 Subpart IIII shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you. [8 CAR § 41-204 and 40 C.F.R. § 60.4218]

SN-29, 30, 31, 32, and 33
Leaks and Oil Vents

Source Description

SN-29 accounts for leaks from the components in the natural gas piping.

SN-30 accounts for leaks from the components in the ammonia piping.

SN-31 accounts for leaks from the components in the diesel fuel piping.

The new combustion turbine and steam turbine will each be equipped with a dedicated lubrication system. Lubrication oil will be circulated through each turbine's machinery from the system's oil sumps. The oil sumps will be equipped with a vent that will be controlled by an oil mist eliminator. Emissions from the oil mist eliminators are based on lube oil replacement rates for similar units equipped with mist eliminators. SN-32 is the combustion turbine lube oil vent. And SN-33 is the steam turbine lube oil vent. Lube oil is brought onto the site in drums and transferred into a lube oil reservoir in the equipment. There will be no lube oil storage tanks stored on site.

Specific Conditions

357. 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 359.a and Plantwide Condition 5. [8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
29	Natural Gas Leaks	VOC CO_2e	0.1 -	0.4 400
31	Diesel Leaks	VOC	0.1	0.1
32	Combustion Turbine Lube Oil Vent	PM PM_{10} $PM_{2.5}$ VOC	0.1 0.1 0.1 0.1	0.1 0.1 0.1 0.1
33	Steam Turbine Lube Oil Vent	PM PM_{10} $PM_{2.5}$ VOC	0.1 0.1 0.1 0.1	0.1 0.1 0.1 0.1

358. 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 359.a and Plantwide Condition. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
29	Natural Gas Leaks	Total HAPs	0.02	0.09
30	Ammonia Leaks	Ammonia	0.1	0.4
31	Diesel Leaks	Total HAPs	0.01	0.01
32	Combustion Turbine Lube Oil Vent	Total HAPs	0.01	0.01
33	Steam Turbine Lube Oil Vent	Total HAPs	0.01	0.01

359. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with these emission limits shall be demonstrated by compliance with Specific Condition a and Plantwide Condition 5. [8 CAR § 41-801, 8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

Source	Description	Pollutant	Control Technology	BACT Limit
SN-29	Natural Gas Leaks	VOC	Audio-Visual-Olfactory (AVO) LDAR Program	0.1 lb/hr, 0.4 tpy
		GHG (CH_4)	Audio-Visual-Olfactory (AVO) LDAR Program	400 tpy CO_2e
SN-31	Diesel Leaks	VOC	Audio-Visual-Olfactory (AVO) LDAR Program	0.1 lb/hr, 0.1 tpy
SN-32	Combustion Turbine Lube Oil Vent	VOC	Mist Eliminator	0.1 lb/hr, 0.1 tpy
		PM / PM_{10} / $PM_{2.5}$ / Opacity	Mist Eliminator	0.1 lb/hr, 0.1 tpy 5% Opacity
SN-33	Steam Turbine Lube Oil Vent	VOC	Mist Eliminator	0.1 lb/hr, 0.1 tpy
		PM / PM_{10} / $PM_{2.5}$ / Opacity	Mist Eliminator	0.1 lb/hr, 0.1 tpy 5% Opacity

a. The permittee shall maintain a leak detection and repair program to limit emissions from SN-29, 30, and 31. All piping components shall be inspected by AVO means at least weekly by operating personnel walk-through. Immediately,

but no later than one hour upon detection of a leak, plant personnel shall take at least one of the following actions:

i. Isolate the leak.
ii. Commence repair or replacement of the leaking component.
iii. Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

b. Damaged or leaking valves, connectors, compressor seals, and pump seals found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging.
c. The date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to AVO-detected leaks.
d. Affected operating staff shall receive annual refresher training on the AVO leak detection and repair program. [8 CAR § 40-904 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

360. Weekly observations of the opacity from sources 32 and 33 shall be conducted by personnel familiar with the permittee's visible emissions. The permittee shall maintain personnel trained in (but not necessarily certified in) EPA Reference Method 9. If visible emissions from any of these sources are detected, the permittee shall take action to identify the cause of the visible emissions, implement corrective action, and document if visible emissions were present following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this condition. These records shall be updated weekly, kept on site, and made available to Division personnel upon request. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]

a. The date and time of the observation.

b. If visible emissions were detected.

c. If visible emissions were detected, the cause of the visible emissions, the corrective action taken, and if the visible emissions were present following the corrective action.

d. The name of the person conducting the opacity observations.

SN-34 and 35
Natural Gas Condensate Tanks 1 and 2

Source Description

SN-34 and 35 are the two 400-gallon fixed-roof natural gas condensate tanks (JPS-NGTK1 and JPS-NGTK2). These tanks will knock out and collect natural gas condensate to prevent it from entering the CT in rare occurrences when condensate is present in the incoming pipeline natural gas. Whenever condensate is collected, it will be removed via vacuum truck.

Specific Conditions

361. 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 Plantwide Condition 5. [8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
34	Natural Gas Condensate Tank 1	VOC	3.5	0.1
35	Natural Gas Condensate Tank 2	VOC	3.5	0.1

362. 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 Plantwide Condition 5. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
34	Natural Gas Condensate Tank 1	Total HAPs	0.02	0.01
35	Natural Gas Condensate Tank 2	Total HAPs	0.02	0.01

363. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with these emission limits shall be demonstrated by compliance with Plantwide Condition 5. [8 CAR § 41-801, 8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

Source	Description	Pollutant	Control Technology	BACT Limit
SN-34	Natural Gas Condensate Tank 1	VOC	White Fixed-Roof Tank, Submerged Fill Pipe, Atmospheric Vent, Good Operating Practices	3.5 lb/hr, 0.1 tpy
SN-35	Natural Gas Condensate Tank 2	VOC	White Fixed-Roof Tank, Submerged Fill Pipe, Atmospheric Vent, Good Operating Practices	3.5 lb/hr, 0.1 tpy

SN-36
Natural Gas Dewpoint Heater

Source Description

Pipeline quality natural gas will be delivered to the site via pipeline where it is metered and piped to the natural gas-fired units. Natural gas fuel to the CT will be indirectly heated in a small 5.01 MMBtu/hr natural-gas fired dewpoint heater, SN-36, (JPS-NGDPHTR). A dewpoint heater is designed to raise the temperature of the natural gas fuel to the CT/duct burner systems to prevent condensation from forming in the natural gas stream. JPS has stated that once the turbine plant is online the existing boilers will have to cease combusting coal and the facility will be an area source of HAPs. Plantwide Conditions were added to make this enforceable so this source is not subject to the major source boiler MACT, Subpart DDDDD.

Specific Conditions

364. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by combustion of natural gas only and compliance with Plantwide Condition 5. [8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
36	Natural Gas Dewpoint Heater	PM	0.1	0.2
		PM_{10}	0.1	0.2
		$PM_{2.5}$	0.1	0.2
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.2	0.9
		NO_x	0.1	0.3
		CO_2e	-	2,600

365. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition combustion of natural gas only and compliance with Plantwide Condition 5. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
36	Natural Gas Dewpoint Heater	Total HAPs	0.01	0.01

366. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with these emission limits shall be demonstrated by

combustion of natural gas only and compliance with Plantwide Condition 5. [8 CAR § 41-801, 8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

Source	Description	Pollutant	Control Technology	BACT Limit
SN-36	Natural Gas Dewpoint Heater	NO_X	Ultra-Low NO_x Burners	0.011 lb/MMBtu
		CO	Good Combustion Practices	0.037 lb/MMBtu
		VOC	Good Combustion Practices	0.008 lb/MMBtu
		PM / PM_{10} / $PM_{2.5}$ / Opacity	Low Sulfur Pipeline Natural Gas, Good Combustion Practices	0.0048 lb/MMBtu Opacity 5%
		GHG	Clean-Burning Efficient Pipeline Natural Gas, Good Combustion Practices	121 lb CO_2e/MMBTU

367. The permittee shall not exceed 5% opacity from SN-36 as measured by EPA Reference Method 9. Compliance for SN-36 shall be demonstrated by only combusting natural gas in SN-36. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Entergy Arkansas, LLC - White Bluff Plant will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future rules and 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. [8 CAR § 41-604, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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. [8 CAR § 41-310(b) and 40 C.F.R. § 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 Division of Environmental Quality or within 180 days of permit issuance if no date is specified. The permittee must notify the Division of Environmental Quality of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Division of Environmental Quality within sixty (60) calendar days after completing the testing. [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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.

    [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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. [8 CAR § 41-203 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [8 CAR pt. 42 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

7. Unless otherwise specified in the permit, approval to construct any new major stationary source or a major modification subject to 40 C.F.R. § 52.21 shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Division of Environmental Quality may extend the 18-month period upon a satisfactory showing that an extension is justified. [8 CAR § 41-801 et seq. and 40 C.F.R. § 52 Subpart E]

8. The permittee shall not operate SN-01, 02, or 05 after start-up of SN-26. [8 CAR § 41-605 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Acid Rain (Title IV)

9. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. A copy of the facility's Acid Rain Permit is attached in an appendix to this Title V permit. [8 CAR § 42-601 and 40 C.F.R. § 70.6(a)(4)]

Transport Rule (TR) NO_X Ozone Season Group 2 Trading Program Requirements

10. The permittee shall comply with the following Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program Requirements. The unit-specific monitoring provisions are attached to this Title V permit. [40 C.F.R. § 97 Subpart EEEEE and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

    a. Designated representative requirements.
    The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 C.F.R. §§ 97.813 through 97.818.
    b. Emissions monitoring, reporting, and recordkeeping requirements.
        i. The owners and operators, and the designated representative, of each TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 C.F.R. §§ 97.830 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold

storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

ii. The emissions data determined in accordance with 40 C.F.R. §§ 97.830 through 97.835 shall be used to calculate allocations of TR NO_X Ozone Season Group 2 allowances under 40 C.F.R. §§ 97.811(a)(2) and (b) and 97.812 and to determine compliance with the TR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 C.F.R. §§ 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c. NO_X emissions requirements.

i. TR NO_X Ozone Season Group 2 emissions limitation.

A. As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 C.F.R. § 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season Group 2 units at the source.

B. If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season Group 2 units at a TR NO_X Ozone Season Group 2 source are in excess of the TR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:

a) The owners and operators of the source and each TR NO_X Ozone Season Group 2 unit at the source shall hold the TR NO_X Ozone Season Group 2 allowances required for deduction under 40 C.F.R. § 97.824(d); and

b) The owners and operators of the source and each TR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 C.F.R. § 97 Subpart EEEEE and the Clean Air Act.

ii. TR NO_X Ozone Season Group 2 assurance provisions.

A. If total NO_X emissions during a control period in a given year from all base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 C.F.R. § 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 C.F.R. § 97.825(b), of multiplying—
    a) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and
    b) The amount by which total NO_X emissions from all base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State for such control period exceed the State assurance level.

B. The owners and operators shall hold the TR NO_X Ozone Season Group 2 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

C. Total NO_X emissions from all base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under 40 C.F.R. § 97.810(a) and the state's variability limit under 40 C.F.R. § 97.810(b).

D. It shall not be a violation of 40 C.F.R. § 97 Subpart EEEEE or of the Clean Air Act if total NO_X emissions from all base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State during a control period exceed the

State assurance level or if a common designated representative's share of total NO_X emissions from the base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State during a control period exceeds the common designated representative's assurance level.

E. To the extent the owners and operators fail to hold TR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,
   a) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
   b) Each TR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 C.F.R. § 97 Subpart EEEEE and the Clean Air Act.

iii. Compliance periods.
   A. A TR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 C.F.R. § 97.830(b) and for each control period thereafter.
   B. A base TR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 C.F.R. § 97.830(b) and for each control period thereafter.

iv. Vintage of TR NO_X Ozone Season Group 2 allowances held for compliance.
   A. A TR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a TR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for such control period or a control period in a prior year.
   B. A TR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a TR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.

v. Allowance Management System requirements. Each TR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 C.F.R. § 97 Subpart EEEEE.

vi. Limited authorization. A TR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:
   A. Such authorization shall only be used in accordance with the TR NO_X Ozone Season Group 2 Trading Program; and
   B. Notwithstanding any other provision of 40 C.F.R. § 97 Subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

vii. Property right. A TR NO_X Ozone Season Group 2 allowance does not constitute a property right.

d. Title V permit requirements.
   i. No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Ozone Season Group 2 allowances in accordance with 40 C.F.R. § 97 Subpart EEEEE.
   ii. This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 C.F.R. §§ 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 C.F.R. § 75 Subparts B and H), an excepted monitoring system (pursuant to 40 C.F.R. § 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 C.F.R. § 75.19), and an alternative monitoring system (pursuant to 40 C.F.R. § 75 Subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 C.F.R. §§ 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

e. Additional recordkeeping and reporting requirements.
   i. Unless otherwise provided, the owners and operators of each TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.
      A. The certificate of representation under 40 C.F.R. § 97.816 for the designated representative for the source and each TR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 C.F.R. § 97.816 changing the designated representative.
      B. All emissions monitoring information, in accordance with 40 C.F.R. § 97 Subpart EEEEE.

C. Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Ozone Season Group 2 Trading Program.

ii. The designated representative of a TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the TR NO_X Ozone Season Group 2 Trading Program, except as provided in 40 C.F.R. § 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 C.F.R. §§ 70 and 71.

f. Liability.

i. Any provision of the TR NO_X Ozone Season Group 2 Trading Program that applies to a TR NO_X Ozone Season Group 2 source or the designated representative of a TR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season Group 2 units at the source.

ii. Any provision of the TR NO_X Ozone Season Group 2 Trading Program that applies to a TR NO_X Ozone Season Group 2 unit or the designated representative of a TR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

g. Effect on other authorities.
No provision of the TR NO_X Ozone Season Group 2 Trading Program or exemption under 40 C.F.R. § 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Ozone Season Group 2 source or TR NO_X Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

Title VI Provisions

11. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 C.F.R. § 82 Subpart E]

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

12. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 C.F.R. § 82 Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156.
    b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158.
    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161.
    d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to § 82.166. ("MVAC like appliance" as defined at § 82.152)
    e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.156.
    f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

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

14. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 C.F.R. § 82 Subpart B, Servicing of Motor Vehicle Air Conditioners.

    The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

15. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 C.F.R. § 82 Subpart G.

SECTION VII: INSIGNIFICANT ACTIVITIES

The Division of Environmental Quality deems the following types of activities or emissions as insignificant on the basis of size, emission rate, production rate, or activity in accordance with Group A of the Insignificant Activities list found in 8 CAR pt. 40 and pt. 41 Appendix A. Group B insignificant activities may be listed but are not required to be listed in permits. Insignificant activity emission determinations rely upon the information submitted by the permittee in an application dated April 28, 2022 and October 20, 2025. [8 CAR § 42-204 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Description	Category
C10 Diesel Fired Space Heaters (36) 14 @ 0.05 mmBTU/hr, 6 @0.17 mmBTU/hr, 16 @ 0.4 mmBTU/hr	A-1
C11 Landfill Contractors Diesel Fired Space heaters 2 @ 0.22 mmBTU/hr	A-1
T6 Unit 1 FD Fan Hydraulic Reservoir	A-2
T7 Unit 1 FD Fan Lube Oil Reservoir	A-2
T8 Unit 1 ID Fan Hydraulic Oil Reservoir	A-2
T9 Unit 1 ID Fan Motor Oil Reservoir	A-2
T10 Unit 1 ID Fan Lube Oil Reservoir	A-2
T15 Unit 2 ID Fan Hydraulic Oil Reservoir	A-2
T16 Unit 2 ID Fan Motor Oil Reservoir	A-2
T17 Unit 2 ID Fan Lube Oil Reservoir	A-2
T18 Unit 2 FD Fan Lube Oil Reservoir	A-2
T19 Unit 2 FD Fan Hydraulic Reservoir	A-2
T96 Unit-1 Lube Purifier/Centrifuge	A-2
T97 Unit-2 Lube Purifier/Centrifuge	A-2
T98 Vacuum Pump Oil Separator (2)	A-2
T99 No. 1A & 1B BFPT Lube Oil Reservoir	A-2
T100 No. 2A & 2B BFPT Lube Oil Reservoir	A-2
T114 Bowl Mill Lube Oil Storage Drums (4)	A-2
T123 Stacker/Reclaimer Lube Oil Storage Tank	A-2
T124 Vacuum Pump Lube Oil Storage Tank #20 (2)	A-2

Description	Category
T125 Bulk Storage Tank #25 and #26	A-2
T126 APH Gear Box Lube Oil Tanks (2)	A-2
T130 Headwaters Rotella T3 15W40 Oil Tank	A-2
T131 Lube Oil House 55 gal drums (10)	A-2
T4 Unit 1 EHC Reservoir	A-3
T5 No. 1 A & 1B BFPT Lube Oil Reservoir	A-3
T13 Unit 2 EHC Reservoir	A-3
T14 No. 2A & 2B BFPT Lube Oil Reservoir	A-3
T21 Used Oil Double Walled Storage Tank	A-3
T22 Bulk Used Oil Storage Tank #13, #13, #14, and #15 (4)	A-3
T24 Mobile Used Oil Storage Tank	A-3
T26 10,000 gal No.2 Fuel Oil Storage Tank	A-3
T27 Mobile Diesel Fuel Storage Tank	A-3
T29 SPCC #11 - Emergency Fire Pump Diesel Fuel Storage Tank	A-3
T30 Bulk Storage Tank #12 - Emergency Diesel Generator Fuel Tank	A-3
T31 Portable Kerosene Storage Skid Tank	A-3
T94 Unit 1 Hydrogen Seal Tank	A-3
T95 Unit 2 Hydrogen Seal Tank	A-3
T121 RCD Wheel Clamp Hydraulic Oil Reservoir	A-3
T122 RCD Car Clamp Hydraulic Oil Reservoir	A-3
T113 Miscellaneous Paint Containers Storage	A-3
T115 Bulk Storage Tank #9 and #10 - Coal Yard Lube Oil, Antifreeze, and Hydraulic Fluid Storage Tanks (3)	A-3
T116 Vehicle Maintenance Lube Oil, Antifreeze and Hydraulic Fluid Storage Tanks (3)	A-3
T120 Main Oil/Water Separator Used Oil Vault	A-3
T127 Skid Mounted Horizontal Diesel Tank	A-3
T128 Headwaters 1,000 Gal Diesel Tank	A-3

Description	Category
T129 Headwaters Used Oil Tank	A-3
T132 1,000 gal No.2 Fuel Oil Storage Tank	A-3
JPS Emergency Generator Diesel Tank	A-3
JPS Emergency Firewater Pump Diesel Tank	A-3
T2 Unit 1 Turbine Lube Oil Storage Tank	A-13
T3 Unit 1 Turbine Lube Oil Reservoir	A-13
T11 Unit 2 Turbine Lube Oil Storage Tank	A-13
T12 Unit 2 Turbine Lube Oil Reservoir	A-13
T71 EHC Fluid Storage	A-13
X15 Unleaded Gasoline Dispensing Station	A-13
X16 Diesel Dispensing Station (2)	A-13
X22 Sand Blasting Booth	A-13
X31 Unit 1 ESP Transformer/Rectifiers	A-13
X32 Unit 2 ESP Transformer/Rectifiers	A-13
X33 Spare Transformers / Rectifiers	A-13
X34 Transformers	A-13
X35 Switchyard Transformers & Oil Circuit Breakers	A-13
X36-X54 AC Chiller Units	A-13
X55 Aerosol Lubricant Fugitives	A-13
X56 Aerosol Degreaser Fugitives	A-13
M60 Unit 1 Economizer Ash Silo	A-13
M61 Unit 2 Economizer Ash Silo	A-13
X57 Unit 1 AC Silo	A-13
X58 Unit 2 AC Silo	A-13
X62 17 Gal Ultrasonic Parts Washer	A-13
X63 Powdered Halide Hoppers (2)	A-13
X64 Bottom Ash Bunker System	A-13

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission 8 CAR pt. 40 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission 8 CAR pt. 40 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission 8 CAR pt. 40 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 C.F.R. § 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 C.F.R. § 70.6(a)(2) and 8 CAR § 42-601(2)]

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 Division of Environmental Quality takes final action on the renewal application. The Division of Environmental Quality will not necessarily notify the permittee when the permit renewal application is due. [8 CAR § 42-306]

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 C.F.R. § 70.6(a)(1)(ii) and 8 CAR § 42-601(1)(C)]

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 C.F.R. § 70.6(a)(3)(ii)(A) and 8 CAR § 42-601(3)(C)]

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 C.F.R. § 70.6(a)(3)(ii)(B) and 8 CAR § 42-601(3)(C)(ii)]

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 8 CAR § 42-104 must certify all required reports. The permittee will send the reports electronically using https://eportal.adeq.state.ar.us or mail them to the address below:

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

[40 C.F.R. § 70.6(a)(3)(iii)(A) and 8 CAR § 42-601(3)(D)(i)]

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

   a. For all upset conditions (as defined in 8 CAR § 41-501), the permittee will make an initial report to the Division of Environmental Quality 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 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 Division of Environmental Quality 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.

[8 CAR § 41-501, 8 CAR § 41-502, 8 CAR § 42-601(3)(D)(ii), and 40 C.F.R. § 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 Rule are declared to be separable and severable. [40 C.F.R. § 70.6(a)(5), Rule 8 CAR § 42-601(5), and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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 8 CAR pt. 42 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 C.F.R. § 70.6(a)(6)(i) and 8 CAR § 42-601(6)(A)]

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 C.F.R. § 70.6(a)(6)(ii) and 8 CAR § 42-601(6)(B)]

12. The Division of Environmental Quality 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 C.F.R. § 70.6(a)(6)(iii) and 8 CAR § 42-601(6)(C)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 C.F.R. § 70.6(a)(6)(iv) and 8 CAR § 42-601(6)(D)]

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 Division of Environmental Quality may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 C.F.R. § 70.6(a)(6)(v) and 8 CAR § 42-601(6)(E)]

15. The permittee must pay all permit fees in accordance with the procedures established in 8 CAR pt. 12. [40 C.F.R. § 70.6(a)(7) and 8 CAR § 42-601(7)]

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 C.F.R. § 70.6(a)(8) and 8 CAR § 42-601(8)]

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 C.F.R. § 70.6(a)(9)(i) and 8 CAR § 42-601(9)(B)(i)]

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 Division of Environmental Quality specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 C.F.R. § 70.6(b) and 8 CAR § 42-602(a) and (b)]

19. Any document (including reports) required by this permit pursuant to 40 C.F.R. § 70 must contain a certification by a responsible official as defined in 8 CAR § 42-104. [40 C.F.R. § 70.6(c)(1) and 8 CAR § 42-603(1)]

20. The permittee must allow an authorized representative of the Division of Environmental Quality, upon presentation of credentials, to perform the following: [40 C.F.R. § 70.6(c)(2) and 8 CAR § 42-603(2)]

    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 Division of Environmental Quality. All compliance certifications required by this permit must include the following: [40 C.F.R. § 70.6(c)(5) and 8 CAR § 42-603(5)(B)(iii)]

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 Division of Environmental Quality 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: [8 CAR § 42-604(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. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 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 Division of Environmental Quality

approval. The Division of Environmental Quality may grant such a request, at its discretion in the following circumstances:

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

[8 CAR § 40-214(a), 8 CAR § 41-316(a), 8 CAR § 42-913(a), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

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 Division of Environmental Quality approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

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

[8 CAR § 40-214(b), 8 CAR § 41-316(b), 8 CAR § 42-913(b), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

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 Division of Environmental Quality approval. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

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

[8 CAR § 40-214(c), 8 CAR § 41-316(c), 8 CAR § 42-913(c), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

27. Any credible evidence based on sampling, monitoring, and reporting may be used to determine violations of applicable emission limitations. [8 CAR § 40-901, 8 CAR § 41-601, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

Appendix A

40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

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

§ 60.40 Applicability and designation of affected facility.

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

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

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

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

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

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

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.

[72 FR 32717, June 13, 2007, as amended at 77 FR 9447, Feb. 16, 2012]

§ 60.41 Definitions.

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

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

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

Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

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

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

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

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has 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), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

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

[72 FR 32717, June 13, 2007, as amended at 77 FR 9447, Feb. 16, 2012]

§ 60.42 Standard for particulate matter (PM).

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

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

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

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

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

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

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO*2* emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO*2* or PM is exempt from the PM standards specified in paragraph (a) of this section.

[60 FR 65415, Dec. 19, 1995, as amended at 76 FR 3522, Jan. 20, 2011; 74 FR 5077, Jan. 28, 2009; 77 FR 9447, Feb. 16, 2012]

§ 60.43 Standard for sulfur dioxide (SO*2*).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO*2* in excess of:

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

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

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

Where:

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

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

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

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

§ 60.44 Standard for nitrogen oxides (NO*X*).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO*X*, expressed as NO*2* in excess of:

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

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

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

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

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

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

Where:

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NO*X* does not apply.

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

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

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO*2* emissions, NO*X* emissions, and either oxygen (O*2*) or carbon dioxide (CO*2*) except as provided in paragraph (b) of this section.

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

(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO*2* emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO*2* or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO*2* emissions are not required if the owner or operator monitors SO*2* emissions by fuel sampling and analysis or fuel receipts.

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

(3) Notwithstanding § 60.13(b), installation of a CEMS for NO*X* may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NO*X* are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NO*X* emissions is not required. If the initial performance test results show that NO*X* emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO*X* within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for either SO*2* or NO*X*, a CEMS for measuring either O*2* or CO*2* is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO*2*, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

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

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

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

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

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

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

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

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

(7) An owner or operator of an affected facility subject to an opacity standard under § 60.42 that elects to not use a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of this section, monitors PM emissions as specified under paragraph (b)(5) of this section, or monitors CO emissions as specified under paragraph (b)(6) of this section, shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.42 by April 29, 2011 or within 45 days after stopping use of an existing COMS, whichever is later, and shall comply with either paragraph (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) 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. The permitting authority may exempt owners or operators of affected facilities burning only natural gas from the opacity monitoring requirements.

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

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

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

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (b)(7) of this section within 45 calendar days according to the requirements in § 60.46(b)(3).

(B) 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.

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

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

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

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

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

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

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

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

1 Not applicable.

Where:

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

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

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

(d) [Reserved]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

(ii) For affected facilities electing to comply with § 60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard in § 60.43.

Facilities complying with the 30-day SO_2 standard shall use the most current associated SO_2 compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part or §§ 60.45b and 60.47b of subpart Db of this part, as applicable.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009; 76 FR 3522, Jan. 20, 2011; 77 FR 9447, Feb. 16, 2012]

§ 60.46 Test methods and procedures.

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

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

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

Where:

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

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

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

(iii) If the particulate run has more than 12 traverse points, the O*2* traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O*2* traverse points.

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

(4) Method 6 of appendix A of this part shall be used to determine the SO*2* concentration.

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

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O*2* concentration (%O*2*). The O*2* sample shall be taken simultaneously with, and at the same point as, the SO*2* sample. The SO*2* emission rate shall be computed for each pair of SO*2* and O*2* samples. The SO*2* emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the NO*X* concentration.

(i) The sampling site and location shall be the same as for the SO*2* sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO*X* sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O*2* concentration (%O*2*). The sample shall be taken simultaneously with, and at the same point as, the NO*X* sample.

(iii) The NO*X* emission rate shall be computed for each pair of NO*X* and O*2* samples. The NO*X* emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

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

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

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

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

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

(1) The emission rate (E) of PM, SO*2* and NO*X* may be determined by using the Fc factor, provided that the following procedure is used:

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

Where:

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

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

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

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

(2) For Method 5 or 5B of appendix A-3 of this part, Method 17 of appendix A-6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The

procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used with Method 17 of appendix A-6 of this part only if it is used after wet FGD systems. Method 17 of appendix A-6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made:

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

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

(4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part data are specified to determine the SO_2 emission rate, under the conditions in paragraph (d)(1) of this section.

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

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

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

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

Appendix B

Continuous Emission Monitoring Systems Conditions

Arkansas Department of Environmental Quality

CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised September 2013

PREAMBLE

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

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

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

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

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

SECTION I

DEFINITIONS

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

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

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

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

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

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

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

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

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

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

SECTION II

MONITORING REQUIREMENTS

** Only CEMS/COMS required by ADEQ permit for reasons other than Part 60, 63 or 75 shall comply with this section.

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

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

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

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

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

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

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

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

I. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ

CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

** All CEMS/COMS shall comply with this section.

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

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

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

D. Each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter.

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

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

G. Quarterly reports shall be used by the Department to determine compliance with the permit.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

** Only CEMS/COMS required by ADEQ permit for reasons other than Part 60, 63 or 75 shall comply with this section.

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

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

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

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

D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three

quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60 Appendix F.

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

E. Criteria for excessive audit inaccuracy.

RATA

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

CGA

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

RAA

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

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

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

Appendix C

Maintenance Plan for SN-04 and Design Specifications for SN-17 and SN-18

White Bluff Fly Ash Silo Baghouse Maintenance Plan

Preventative maintenance conducted as scheduled in AIM, Maintenance Management System.

PM Check sheets are associated with each individual PM, not Fly ash Silo baghouse system as a whole

1. Check/Adjust Fan, Blowback Exh Baghouse Filter

2. Check/Adjust Blowback Baghouse Filter

3. Check/Adjust Fan, Exh. Baghouse Filter

4. Check/Adjust Filter, Baghouse
   a. Check for air leaks on pulsation system.
   b. Check operation of air operated valves.
   c. Check piping and supports.
   d. Check air cylinders.
   e. Check bag house doors and seals.
   f. Check diffuser blower bearings for heat, vibration, and lubrication leaks.
   g. Check bags and change as needed.
   h. Check blower for excessive heat buildup.
   i. Check inlet filter and change as needed.

5. Check/Adjust WS Dust Baghouse

6. Check/Adjust Traveler Baghouse Filter

7. Check/Adjust Chute, Telescopic, East, West Fly Ash Silo

8. Check/Adjust Fly Ash Diffuser Bower

NATURAL DRAFT COOLING TOWER

OPERATING AND MAINTENANCE INSTRUCTIONS

ARKANSAS POWER AND LIGHT

White Bluff STEAM ELECTRIC STATION

UNITS #1 AND #2

RESEARCH-COTTRELL, INC.

HAMON COOLING TOWER DIVISION

P.O. BOX 1500

SOMERVILLE, NEW JERSEY 08876

SECTION 1

GENERAL DESCRIPTION

1.1 Description of the Tower

1.1.1 Introduction

Units No. 1 and 2 of the Arkansas Power and Light White Bluff Steam Electric Station are each equipped with a natural draft cooling tower. Each tower is designed according to the counter-flow principle and incorporates asbestos cement fill sheets as the heat transfer surface to assure maximum availability for year-round operation, to minimize maintenance, and to virtually eliminate any necessity for replacement of parts or material.

Each tower consists of five major parts:

1) The basin, to catch and store the cooled water;
2) The fill or heat transfer surface, where the hot water and cooling air come into contact;
3) The distribution system, to distribute the hot water evenly over the fill;
4) The drift eliminator section, to reduce water droplet carry-over;
5) The chimney or veil, to create the draft necessary for tower operation.

Each tower is also equipped with a lightning protection system.

1.1.2 Basin

The cold water basin covers the entire base of the tower and is 314 feet in diameter. It contains approximately 2,900,000 gallons of water when filled to operating level, one foot below the top of the basin wall.

1.1.3 Fill

The fill consists of a variable number of tiers of asbestos cement fill sheets, supported by concrete columns and precast beams.

1.1.4 Distribution System

Warm water enters the tower from the condenser outlet through one concrete pipe that supplies water to three risers in-line. These risers are 114, 102 and 84 inches in diameter and supply water to concrete distribution flumes.

Each flume is fitted with asbestos-cement distribution pipes that distribute the warm water to all sections of the tower fill. Each segment of pipe is fitted with evenly-spaced nozzles made of plastic and fitted with a splashplate. These distribute the water uniformly over the entire fill.

The water leaving the splashplates falls onto the fill sheets, runs down the sheets and then falls to the cold water basin below. The falling wat

1.1.5 Drift Eliminators

Immediately above the distribution piping network are the drift eliminator waves supported by the concrete structure. The drift eliminators reduce the quantity of water droplets entrained in the air that leave the tower as drift.

1.1.6 Veil

The veil is constructed of reinforced concrete. It is 393 feet high (from the top of the basin wall) and has a minimum wall thickness of 7 inches. The shell is supported by diagonal columns that provide an open air inlet at the base of the tower. The hyperbolic shape of the shell is for economic and structural reasons.

1.1.7 Deicing System

Operational control during normal winter conditions is provided by the deicing system. Deicing is provided by slide gates in two of the risers that can stop the flow of water to the central portion of the tower, thereby increasing the water flow and heat load to the peripheral portions of the tower. In this way, ice formation on the fill is prevented.

1.1.8 Bypass System

A bypass system has been provided to prevent icing of the fill during a freezing weather start-up. When the unit is started up during freezing weather, the warm water flow to the tower fill should be bypassed into the cold water basin. Operation of the bypass is covered in paragraphs 4.3.3 and 4.3.4.

1.2 Principle of Operation

The function of the cooling tower is to cool the water entering the tower at a particular temperature to a lower, specified temperature so that it can be recycled. The tower utilizes cool ambient air in such a way that heat is transferred from the hot water to the cool air through both latent heat transfer and, to a lesser extent, sensible heat transfer.

Hot water evaporates when exposed to cool air. Approximately 1000 BTU of heat per pound of water evaporated is consumed; this heat is taken from the water remaining after evaporation by lowering its temperature. This transfer of latent heat accounts for approximately 75% of the heat transfer that occurs. The rest involves sensible heat exchange. When two masses having different temperatures come into contact, heat is exchanged with the result that their temperatures approach an equilibrium. When warm water contacts cool air in the tower, the air is warmed because it receives sensible heat from the water; the water in turn loses sensible heat and is cooled.

As the air is warmed, it also becomes lighter. The difference in specific weight between the air inside and outside the tower causes the natural draft through the tower. The actual transfer of heat from the water to the air is accomplished primarily in the fill, where warm water is passed downward in very thin films through a stream of air moving upward as a result of the natural draft. The fill is designed to maximize the surface area of the water exposed to air, thereby maximizing the amount of evaporation that occurs. The warmed, moist air is then drawn upward through the drift eliminators by the natural draft. The drift eliminators, composed of panels containing wave-shaped passages, are designed to reduce the amount of water leaving the tower as droplets with the warmed air. By causing the air to change direction, the drift eliminators collect many of the water droplets carried by the air. The warm air is then discharged into the atmosphere and the cooled water falls to the basin to be recycled.

1.3 Material List of Non-Concrete Materials

1.3.1 Fill

Fill Sheets	- Asbestos cement, Type II cement.
Fill Spacers	- Polystyrene. Burning Rate 1.4 in./min. by ASTM D-635.

1.3.2 Drift Eliminators

Drift Eliminator Waves	- Asbestos cement, Type II cement.
Drift Eliminator Spacers	- Polyethylene Flame Spread Rating = 1.4"/min. by ASTM D-635
Drift Eliminator Hardware	- Stainless Steel, Type 304

1.3.3 Distribution System

Distribution Piping	- Asbestos-Cement, ASTM C-428 Type I Autoclave Cured or Equal; Not Combustible.
Pipe Hangers	- Stainless Steel, Type 304
Splashplate	- Acetal
Plastic Nozzle Parts	- Polyethylene and Phenylene Oxide, Flame Spread Rating = 1.04"/min. by ASTM D-635.
Plastic Nozzle Hardware	- Stainless Steel, Type 304
End Plugs	- Polystyrene ASTM D-1892 with Neoprene Gaskets and 304 Stainless Steel Hardware and End Pins.

1.3.4 Miscellaneous

Veil Access Door	- Redwood and Stainless Steel Type 304, heavy-duty construction
Windscreen	- Precast concrete frame with fiberglass panels
Access Hatches	- Fiberglass Panel - Robertson Resolite, Fire Snuf 35.

1.4 Operating Specifications - Design Conditions

Heat Load	- 4.36×10^9 BTU/hr
Waterflow	- 310,000 GPM
Range	- 28.1 degrees F
Wet Bulb	- 78 degrees F
Dry Bulb	- 94 degrees F
Cold Water	- 95 degrees F
Approach	- 17 degrees F
Relative Humidity	- 50 percent
Evaporative Loss*	- 2.46 percent
Drift Loss*	- 0.01 percent

See performance curves in Section 6.1 for additional data.

*Percent of circulating waterflow.

SECTION 2

CIRCULATING WATER QUALITY

2.1 Conditions to be Maintained

For continued maximum cooling tower performance and material life, the circulating water should be subjected to regular analysis to ensure that the following conditions exist. In addition to maintaining the integrity of the concrete components of the tower, these conditions will also ensure that there is no detrimental effect to any plastic materials. Any deviations from these conditions should be kept as short as possible.

2.1.1 The Langelier Index should be maintained at zero or at a slightly positive value, and not less than -0.1.

2.1.2 The pH should not be less than 6.5, as determined at 25 degrees C (77 degrees F).

2.1.3 Concentrations of chemicals harmful to cement should be maintained below reasonable levels, with particular attention being paid to the following:

(SO_4)	Not to exceed 1,000 ppm
(S^-)	Not to exceed 2 ppm
(NH_4^+)	Not to exceed 5 ppm

2.1.4 Aromatic hydrocarbons (organic solvents) and petroleum-based substances should not be allowed to circulate in the cooling system because of possible damage to plastic materials.

2.1.5 Algae formation and growth should be adequately controlled.

2.2 Desilting

Significant amounts of mud or suspended matter will normally be sufficiently taken care of through the normal maintenance procedures (Section 3), but abnormal conditions may require the institution of more frequent desilting.

2.3 Make-Up and Blow-Down

2.3.1 The evaporation process results in a loss of water from the closed-circulating water system. At full load, the evaporation loss is approximately 7600 GPM and the drift loss is approximately 30 GPM. When water is removed by the evaporation process, no dissolved solids are removed and, in time, the circulating water will contain more solids than can remain in solution. In order to prevent this condition, which would scale and foul the components of the system, blow-down is required.

2.3.2 The amount of make-up water to be supplied to the cooling tower should be sufficient to compensate for the evaporation losses, the drift losses, plus the calculated blow-down necessary for optimum concentration within the cooling water circuit.

Appendix D

Dust Control Plan for SN-19

White Bluff Plant
Barge Unloading Operation
Haul Road Dust Control Plan

This Dust Control Plan is only required when the Barge Unloading Facility is in operation. This Dust Control Plan only applies to the paved and unpaved road sections used to transport coal, by truck, from the barge unloading facility to the coal yard.

Paved Roads:
Paved roads will be mechanically swept once weekly. Wetting agent (water or other non-VOC, non-HAP material) will be applied as needed to keep the paved roads wet. Paved roads shall be kept wet at all times when the temperature is greater than 40° F. Wetting will not be required when the temperature is equal to or less than 40℉. Sweeping will be required twice weekly when the temperature is equal to or less than 40℉ for more than three (3) consecutive days.

Unpaved Roads:
A non-VOC, non-HAP chemical dust suppressant will be applied to the unpaved road section as needed to control dust.
A MSDS will be maintained on site to demonstrate a non-VOC, non-HAP dust suppressant is used.

Appendix E

Acid Rain Permit Application

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ **new** ☐ **revised** ☐ **for ARP permit renewal**

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code

Note: Entergy Arkansas, LLC is **building a new natural gas-fired combined cycle combustion turbine power plant adjacent to the existing White Bluff Station. The new plant will be called the Jefferson Power Station (JPS).**

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
	Yes

Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

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

(2) The owners and operators of each affected source and each affected unit at the source shall:
   (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
   (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
   (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
   (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
   (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
   (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

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

Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

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

Recordkeeping and Reporting Requirements

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

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Certification

Read the certification statement, sign, and date.

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

Name	
Signature	Date

Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the Title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the Title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the Title V permitting authority.

STEP 1 A Plant Code is a 4- or 5-digit number assigned by the Department of Energy's (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, send an email to the EIA. The email address is EIA-860@eia.gov.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the Title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a Title V permit, or such longer time as provided for under the Title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate Title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Clean Air Markets Hotline at (202) 343-9620.

Paperwork Burden Estimate

This collection of information is approved by OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. (OMB Control No. 2060-0258). Responses to this collection of information are mandatory (40 CFR 72.30 and 72.31). An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The public reporting and recordkeeping burden for this collection of information is estimated to be 8 hours per response. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the Regulatory Support Division Director, U.S. Environmental Protection Agency (2821T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

Appendix F

Clean Air Interstate Rule (CAIR) Permit Application

TITLE V PERMIT
SUPPLEMENTAL PACKAGE
CLEAN AIR INTERSTATE RULE PERMIT APPLICATION

AFIN:	35-00110	Date:	4/22/2008

1. UNIT INFORMATION

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

Source Number	Description
SN-01	Unit 1 Boiler
SN-02	Unit 2 Boiler

2. STANDARD REQUIREMENTS

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

NO_x Ozone Season Emission Requirements

§ 96.306 Standard requirements

(a) *Permit requirements.*

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

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

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

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

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

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

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

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

(d) *Excess emissions requirements.*

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

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

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

(g) *Effect on other authorities.*

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

3. CERTIFICATION

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

CAIR Designated Representative

Myra Glover **Name (Print)** Myra H. Glover	
Signature Myra H. Glover	**Date** 4/28/08

Appendix G

40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source:69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 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 as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major

source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013; 89 FR 70515, Aug. 30, 2024]

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) [Reserved]

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013, as amended at 85 FR 78463, Dec. 4, 2020; 87 FR 48607, Aug. 10, 2022]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) 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 which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

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

Where:

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(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:

Where:

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

Where:

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

Where:

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of

formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

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

(3) 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;

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

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

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.*, operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.*, wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

(j) Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test following the procedure specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013; 89 FR 70516, Aug. 30, 2024]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O*2* or CO*2* according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO*2* concentration.

(5) Beginning on February 26, 2025, within 60 days after the date of completing each continuous emissions monitoring system (CEMS) performance evaluation (as defined in § 63.2) that includes a relative accuracy test audit (RATA), you must submit the results of the performance evaluation following the procedures specified in § 63.9(k). The results of performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website. The results of performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be included as an attachment in the ERT or alternate electronic file.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

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

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) 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:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of table 2c to this subpart or in items 1 or 4 of table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil and filter change requirement in tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of table 2c to this subpart or in items 5, 6, 7, 8, 10, 11, or 13 of table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil and filter change requirement in tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business

days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013; 89 FR 70516, Aug. 30, 2024]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O*2* using one of the O*2* measurement methods specified in Table 4 of this subpart. Measurements to determine O*2* concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O*2* emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O*2* using one of the O*2* measurement methods specified in Table 4 of this subpart. Measurements to determine O*2* concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O*2* emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4), 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 RICE in emergency situations.

(2) You may operate your emergency stationary RICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE 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 RICE beyond 100 hours per calendar year.

(ii)-(iii) [Reserved]

(3) Emergency stationary RICE located at major sources of HAP 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 provided in paragraph (f)(2) of this 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 supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP 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 provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this 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:

(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.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an initial notification not later than December 13, 2004, or no later than 120 days after the source becomes subject to this subpart, whichever is later. Beginning on February 26, 2025, submit the notification electronically in portable document format (PDF) consistent with § 63.9(k).

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an initial notification not later than 120 days after you become subject to this subpart. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an initial notification not later than July 16, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008, and you are required to submit an initial notification, you must submit an initial notification not later than 120 days after you become subject to this subpart. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) Before February 26, 2025, for each initial compliance demonstration required in table 5 to this subpart that includes a performance test conducted according to the requirements in table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2). Beginning on February 26, 2025, for each initial compliance demonstration required in table 5 to this subpart that includes a performance test conducted according to the requirements in table 3 to this subpart, you must submit the Notification of Compliance Status, including a summary of the performance test results, in PDF to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), before the close of business on the 60th day following the completion of the performance test following the procedure specified in § 63.9(k), except any Confidential Business Information (CBI) is to be submitted according to paragraphs (h)(2)(i) and (ii) of this section. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report, you must submit a complete file, including information claimed to be CBI, to the EPA following the procedures in paragraphs (h)(2)(i) and (ii) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (h)(2).

(i) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described in paragraph (h)(2) of this section, should include clear CBI markings and be flagged to the attention of the Reciprocating Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(ii) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711, Attention Reciprocating Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013; 85 FR 73912, Nov. 19, 2020; 89 FR 70516, Aug. 30, 2024]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (8) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

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

(4) If you had a malfunction during the reporting period, the compliance report must include the starting and ending date and time, the duration (in hours), and a brief description for each malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(7) Engine site rating in brake HP, year construction of the engine commenced (as defined in § 63.2, where the exact year is not known, provide the best estimate), and type of engine (CI, SI 2SLB, SI 4SLB, or SI 4SRB).

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

(9) An engine can be claimed as exempt from reporting coordinates (latitude/longitude) via CEDRI if:

(i) During the reporting period, the engine will be owned by, or operated by or for, an agency of the Federal Government responsible for national defense; and

(ii) The agency determines that disclosing the coordinates to the general public would be a threat to national security.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (8) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time (in hours) of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration (in hours), and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(3) A description of any changes in processes, or controls since the last reporting period.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (8) and (e)(1) through (13) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The start and end date and time and the duration (in hours) that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The start and end date and time and the duration (in hours) that each CMS was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration (in hours) of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration (in hours) of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration (in hours) of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) [Reserved]

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(13) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. Beginning on February 26, 2025, the semiannual and annual compliance report required in table 7 of this subpart must be submitted according to paragraph (i) of this section. Only those elements required under this subpart are required to be submitted according to paragraph (i) of this section.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(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 in brake HP, year construction of the engine commenced (as defined in § 63.2, where the exact year is not known, provide the best estimate), and type of engine (CI, SI 2SLB, SI 4SLB, or SI 4SRB).

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

(v)-(vi) [Reserved]

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(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 § 63.6604 that apply to the engine (if any), 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 § 63.6604 that apply to the engine (if any), information on the number, duration (in hours), and cause of deviations, and the corrective action taken.

(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) Before February 26, 2025, 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) (*https://cdx.epa.gov/*). 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 § 63.13. Beginning on February 26, 2025, the annual report must be submitted according to paragraph (i) of this section.

(i) Beginning on February 26, 2025 for the annual report specified in § 63.6650(h) and February 26, 2025 or one year after the report becomes available in CEDRI, whichever is later for all other semiannual or annual reports, submit all semiannual and annual subsequent compliance reports using the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart and following the procedure specified in § 63.9(k), except any CBI must be submitted according to the procedures in § 63.6645(h). The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022; 89 FR 70517, Aug. 30, 2024]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

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

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must 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. If the engine is used for the purpose specified in § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022; 89 FR 70518, Aug. 30, 2024]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 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. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether 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 paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

[69 FR 33506, June 15, 2004, as amended at 89 FR 70518, Aug. 30, 2024]

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

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

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) 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; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

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 fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE 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 RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO*2*.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO*X*) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO*X*, CO, and volatile organic compounds (VOC) into CO*2*, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production

equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C*3*H*8*.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO*X* (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-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 reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013; 87 FR 48608, Aug. 10, 2022]

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. 1
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O*2*	

1 Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O*2* and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F. 1
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of	

formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and not using NSCR.	

1 Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. 1
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O2	

1 Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F. 1
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F. 1
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.

New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

1 Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions

For each . . .	**You must meet the following requirement, except during periods of startup . . .**	**During periods of startup you must . . .**
1. Emergency stationary CI RICE and black start stationary CI RICE 1	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first 2. b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. 3
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary 3	
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first 2.	
	b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary 3	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
6. Emergency stationary SI RICE and black start stationary SI RICE. 1	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 2	
	b. Inspect spark plugs every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary 3	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 2	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	

	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary 3	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 2	
	b. Inspect spark plugs every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary 3	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2	

1 If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

2 Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2c of this subpart.

3 Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[89 FR 70518, Aug. 30, 2024]

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	**You must meet the following requirement, except during periods of startup . . .**	**During periods of startup you must . . .**
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 1 b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	

4. Emergency stationary CI RICE and black start stationary CI RICE. 2	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 1	
	b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year. 2	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 1 b. Inspect spark plugs every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 1	
	b. Inspect spark plugs every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 1	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 1	
	b. Inspect spark plugs every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 1	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	

11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 1	
	b. Inspect spark plugs every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; 1 b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	

1 Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.

2 If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[89 FR 70520, Aug. 30, 2024]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	**Complying with the requirement to . . .**	**You must . . .**
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually. 1
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually. 1
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually. 1
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

1 After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO, 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 *and* 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 the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005) 1 3 (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device; and	(2) ASTM D6522-00 (Reapproved 2005) 1 2 3 (heated probe not necessary) or method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.
		iv. Measure moisture content at the inlet and outlet of the control device as needed to determine CO and O_2 concentrations on a dry basis	(3) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03 1 3	(d) Measurements to determine moisture content must be made at the same time and location as the measurements for CO concentration.
2. 4SRB stationary RICE	a. Reduce formaldehyde or THC emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, THC, 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 *and* 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, 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.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005) 1 3 (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device as needed to determine formaldehyde or THC and O_2 concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03 1 3	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03, 1 3 provided in ASTM D6348-03 Annex A5 (Analyte Spiking	(d) Formaldehyde 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.

		the inlet and the outlet of the control device	Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(4) (1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(e) THC 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.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, 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 *and* 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, 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. 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 RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005) 1 3 (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location as needed to determine formaldehyde or CO and O_2 concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03 1 3	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03, 1 3 provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde 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.
		v. Measure CO at the exhaust of the stationary RICE	(4) Method 10 of 40 CFR part 60, appendix A-4, ASTM D6522-00 (2005), 1 3 method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03 1 3	(e) CO 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.

1 You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).

2 You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

3 Incorporated by reference, see § 63.14.

[88 FR 18413, Mar. 29, 2023]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O*2* or CO*2* at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O*2* or CO*2* at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction

		of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O*2*, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O*2*, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O*2*, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O*2*;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O*2*, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	**Complying with the requirement to . . .**	**You must demonstrate continuous compliance by . . .**
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved a; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved a; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent. a
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit a; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the

		catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit a; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow 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.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and

		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O*2*; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O*2*, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

a After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in § 63.6650, you must comply with the following requirements for reports:

For each . . .	**You must submit a . . .**	**The report must contain . . .**	**You must submit the report . . .**
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) and (i) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)-(9) and (i) for engines that are limited use stationary RICE subject to

or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP		or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	numerical emission limitations. i. Semiannually according to the requirements in § 63.6650(b) and (i).
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4)	i. Semiannually according to the requirements in § 63.6650(b) and (i).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) and (i).
4. Emergency stationary RICE that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in § 63.6650(h)(1)	i. Annually according to the requirements in § 63.6650(h)(2)-(3) and (i).

[89 FR 70522, Aug. 30, 2024]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ

As stated in § 63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions	Yes	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes	
§ 63.4	Prohibited activities and circumvention	Yes	
§ 63.5	Construction and reconstruction	Yes	
§ 63.6(a)	Applicability	Yes	
§ 63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes	
§ 63.6(b)(5)	Notification	Yes	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes	
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes	
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No	
§ 63.6(f)(1)	Applicability of standards	No	
§ 63.6(f)(2)	Methods for determining compliance	Yes	
§ 63.6(f)(3)	Finding of compliance	Yes	
§ 63.6(g)(1)-(3)	Use of alternate standard	Yes	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria	Yes	

§ 63.6(j)	Presidential compliance exemption	Yes	
§ 63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes	
§ 63.7(e)(1)	Conditions for conducting performance tests	No	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes	
§ 63.7(f)	Alternative test method provisions	Yes	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes	
§ 63.7(h)	Waiver of tests	Yes	
§ 63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No	
§ 63.8(b)(1)	Monitoring	Yes	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes	
§ 63.8(c)(1)	Monitoring system operation and maintenance	Yes	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§ 63.8(c)(2)-(3)	Monitoring system installation	Yes	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§ 63.8(d)	CMS quality control	Yes	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS.
			Except that § 63.8(e) only applies as specified in § 63.6645.
§ 63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that § 63.8(f)(4) only applies as specified in § 63.6645.
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that § 63.8(f)(6) only applies as specified in § 63.6645.
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements	Yes	
§ 63.9(b)(1)-(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved.
			Except that § 63.9(b) only applies as specified in § 63.6645.
§ 63.9(c)	Request for compliance extension	Yes	Except that § 63.9(c) only applies as specified in § 63.6645.
§ 63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that § 63.9(d) only applies as specified in § 63.6645.
§ 63.9(e)	Notification of performance test	Yes	Except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.

§ 63.9(g)(1)	Notification of performance evaluation	Yes	Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use. Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
			Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes	
§ 63.9(j)	Change in previous information	Yes	
§ 63.9(k)	Electronic reporting procedures	Yes	Only as specified in §§ 63.9(j), 63.6620, 63.6625, 63.6645, and 63.6650.
§ 63.10(a)	Administrative provisions for recordkeeping/ reporting	Yes	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§ 63.10(b)(2)(i)-(v)	Records related to SSM	No	
§ 63.10(b)(2)(vi)-(xi)	Records	Yes	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes	
§ 63.10(b)(3)	Records of applicability determination	Yes	
§ 63.10(c)	Additional records for sources using CEMS	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes	
§ 63.10(d)(2)	Report of performance test results	Yes	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No	
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports	No	Excess emissions and exceedance reporting is specified in § 63.6650.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting	Yes	
§ 63.11	Flares	No	
§ 63.12	State authority and delegations	Yes	
§ 63.13	Addresses	Yes	
§ 63.14	Incorporation by reference	Yes	
§ 63.15	Availability of information	Yes	

[89 FR 70522, Aug. 30, 2024]

Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O*2*) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O*2*).

Analyte	CAS No.	Sensitivity

Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O*2*, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O*2* gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 Measurement System. The total equipment required for the measurement of CO and O*2* concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O*2* and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO*2* are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O*2* concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O*2*; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or

scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O*2*. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O*2*) is acceptable for calibration of the O*2* cell. If needed, any lower percentage O*2* calibration gas must be a mixture of O*2* in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O2 Calibration Gas Concentration.

Select an O*2* gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O*2*. When the average exhaust gas O*2* readings are above 6 percent, you may use dry ambient air (20.9 percent O*2*) for the up-scale O*2* calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO*2*).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O*2* concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O*2* and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O*2* for the O*2* channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until

readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O*2*, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O*2*, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O*2* concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the “measurement data phase”.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the “measurement data phase”. The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO*2* gas standards that are generally recognized as representative of diesel-fueled engine NO and NO*2* emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO*2* interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average “measurement data phase” CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

Table 1: Appendix A—Sampling Run Data.

Facility_____ Engine I.D._____ Date_____				
Run Type:	(_)	(_)	(_)	(_)
(X)	Pre-Sample Calibration	Stack Gas Sample	Post-Sample Cal. Check	Repeatability Check

Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
″											
″											
″											
″											
Measurement Data Phase											
″											
″											
″											
″											
″											
″											
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″											
″											
Mean											
Refresh Phase											
″											
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″											

[78 FR 6721, Jan. 30, 2013]

Appendix H

40 CFR Part 60, Subpart IIII – 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, 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; 86 FR 34357, June 29, 2021]

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 1039.101, 1039.102, 1039.104, 1039.105, 1039.107, and 1039.115 and 40 CFR part 1039, appendix I, 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 appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated 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) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the following locations:

(1) Remote areas of Alaska; 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.

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECDs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34357, June 29, 2021]

§ 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 Tier 2 emission standards for new nonroad CI engines for the appropriate rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 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 rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 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 Tier 2 emission standards as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105.

(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 appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated 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 ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section. Engines that would be subject to the Tier 4 standards in 40 CFR part 1042 that are used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section may instead continue to be certified to the previous tier of standards in 40 CFR part 1042. The previous tier is Tier 3 in most cases; however, the previous tier is Tier 2 if there are no Tier 3 standards specified for engines of a certain size or power rating.

(1) Remote areas of Alaska; 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; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021; 88 FR 4471, Jan. 24, 2023]

§ 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 Tier 1 emission standards in 40 CFR part 1042, appendix I.

(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.

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

§ 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 Tier 1 emission standards in 40 CFR part 1042, appendix I.

(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 · n−*0.2* g/KW-hr (34 · 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 · n−*0.23* g/KW-hr (33 · 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; 86 FR 34358, June 29, 2021]

§ 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) [Reserved]

(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 1090.305 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 must use diesel 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; 85 FR 78463, Dec. 4, 2020]

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 1039, subpart C, and must test their engines as specified in 40 CFR part 1039. For the purposes of this subpart, engines certified to the standards in Table 1 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I. For the purposes of this subpart, engines certified to the standards in Table 4 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I, 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 1042, subpart C, and must test their engines as specified in 40 CFR part 1042.

(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 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 part 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 part 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 part 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 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all the requirements in 40 CFR 1039.665 that apply to manufacturers. Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR part 1039, appendix I, when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in sufficient detail to

support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

(k) Manufacturers of any size may certify their emergency stationary CI internal combustion engines under this section using assigned deterioration factors established by EPA, consistent with 40 CFR 1039.240 and 1042.240.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

§ 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 part 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 to emission standards for the same model year and maximum engine power as described in 40 CFR parts 1039 and 1042, as applicable. 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, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3), 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 the purpose specified in paragraph (f)(2)(i) 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)-(iii) [Reserved]

(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 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.

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021; 87 FR 48605, Aug. 10, 2022]

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. Alternatively, stationary CI ICE that are complying with Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or with Tier 2 emission standards as described in 40 CFR part 1042, appendix I, may follow the testing procedures specified in § 60.4213, as appropriate.

(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 subject to Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or Tier 2 emission standards as described in 40 CFR part 1042, appendix I, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard, determined from the following equation:

Where:

(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:

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; 86 FR 34359, June 29, 2021]

§ 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:

Where:

(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.

Where:

(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:

Where:

(ii) Calculate the CO*2* correction factor for correcting measurement data to 15 percent O*2*, as follows:

Where:

(iii) Calculate the NO*X* and PM gas concentrations adjusted to 15 percent O*2* using CO*2* as follows:

Where:

(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:

Where:

(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:

Where:

[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. Beginning on February 26, 2025, submit the notification electronically according to paragraph (g) 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 for the purpose 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)-(vi) [Reserved]

(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) (*https://cdx.epa.gov/*). 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. Beginning on February 26, 2025, submit annual report electronically according to paragraph (g) of this section.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).

(f) Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test required under this section following the procedures specified in paragraphs (f)(1) and (2) of this section.

(1) *Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), according to paragraph (g) of this section. The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI according to paragraph (g) of this section.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI.

Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov*, and as described in paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.*, hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.*, large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 87 FR 48606, Aug. 10, 2022; 89 FR 70512, Aug. 30, 2024]

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 remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the Tier 2 or Tier 3 emission standards described in 40 CFR part 1042 for the same model year, displacement, and maximum engine power, as appropriate, rather than the otherwise applicable requirements of 40 CFR part 1039, as indicated in §§ 60.4201(f) and 60.4202(g).

(c) Manufacturers, owners, and operators of stationary CI ICE that are located in remote areas of Alaska 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 nonemergency CI ICE, the owner or operator of any such engine must have that engine certified as meeting at least the Tier 3 PM standards identified in appendix I of 40 CFR part 1039 or in 40 CFR 1042.101.

(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 remote areas of Alaska.

(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 remote areas of Alaska 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, as amended at 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021]

§ 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 General Provisions and confidential information provisions apply to me?

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

(b) The provisions of 40 CFR 1068.10 and 1068.11 apply for engine manufacturers. For others, the general confidential business information (CBI) provisions apply as described in 40 CFR part 2.

[88 FR 4471, Jan. 24, 2023]

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.

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

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 1042.101(e).

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)(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.

Remote areas of Alaska means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

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 IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34360, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

Table 1 to Subpart IIII 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)**	**Emission standards for stationary fire pump engines in g/KW-hr (g/HP-hr)**		
		NMHC + NO_X	**CO**	**PM**
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
KW<8 (HP<11)	2011 +	7.5 (5.6)	8.0 (6.0)	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)
8≤KW<19 (11≤HP<25)	2011 +	7.5 (5.6)	6.6 (4.9)	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)
19≤KW<37 (25≤HP<50)	2011 +	7.5 (5.6)	5.5 (4.1)	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)
37≤KW<56 (50≤HP<75)	2011 + 1	4.7 (3.5)	5.0 (3.7)	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)
56≤KW<75 (75≤HP<100)	2011 + 1	4.7 (3.5)	5.0 (3.7)	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)
75≤KW<130 (100≤HP<175)	2010 + 2	4.0 (3.0)	5.0 (3.7)	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)
130≤KW<225 (175≤HP<300)	2009 + 3	4.0 (3.0)	3.5 (2.6)	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)
225≤KW<450 (300≤HP<600)	2009 + 3	4.0 (3.0)	3.5 (2.6)	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)
450≤KW≤560 (600≤HP≤750)	2009 +	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
KW>560 (HP>750)	2008 +	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)

1 For 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.

2 For 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.

3 In 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.

[89 FR 70513, Aug. 30, 2024]

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

1 Engine speed: ±2 percent of point.

2 Torque: 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 combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO*X* emissions by 90 percent or more;	i. Select the sampling port location and number/ location of traverse points at the inlet and outlet of the control device;		(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 *and* 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 *and* 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	

Appendix I

40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Source:77 FR 9464, Feb. 16, 2012, unless otherwise noted.

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in § 63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in § 63.10042 of this subpart.

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in § 63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in § 63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, and if you commence reconstruction after May 3, 2011.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after April 16, 2012, due to a change in process (*e.g.*, fuel or utilization) is considered to be an existing source under this subpart.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013; 85 FR 20850, Apr. 15, 2020]

§ 63.9983 Are any fossil fuel-fired electric generating units not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a major source stationary combustion turbine subject to subpart YYYY of this part and any unit designated as an area source stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and that meets the definition of a natural gas-fired EGU in § 63.10042.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but does not meet the definition of a coal- or oil-fired EGU because it did not fire sufficient coal or oil to satisfy the average annual heat input requirement set forth in the definitions for coal-fired and oil-fired EGUs in § 63.10042. Heat input means heat derived from combustion of fuel in an EGU 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 industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

(e) Any electric utility steam generating unit that meets the definition of a natural gas-fired EGU under this subpart and that fires at least 10 percent biomass is an industrial boiler subject to standards established under subpart DDDDD of this part, if it otherwise meets the applicability provisions in that rule.

[77 FR 9464, Feb. 16, 2012, as amended at 81 FR 20180, Apr. 6, 2016]

§ 63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in § 63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015, except as provided in paragraph (g) of this section.

(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under § 63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in § 63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), (e), or (g) of this section.

(g) If you own or operate an EGU that is in the *Unit designed for eastern bituminous coal refuse (EBCR) subcategory* as defined in § 63.10042, you must comply with the applicable hydrogen chloride (HCl) or sulfur dioxide (SO_2) requirements of this subpart no later than April 15, 2020.

[77 FR 9464, Feb. 16, 2012, as amended at 85 FR 20850, Apr. 15, 2020]

§ 63.9985 What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.

(2) An EGU that commenced reconstruction after May 3, 2011.

(b) [Reserved]

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012]

Emission Limitations and Work Practice Standards

§ 63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (3) of this section and as defined in § 63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb,

(2) EGUs designed for low rank virgin coal, and

(3) EGUs designed for EBCR.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in § 63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

[77 FR 9464, Feb. 16, 2012, as amended at 85 FR 20850, Apr. 15, 2020]

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under § 63.10009.

(2) You must meet each operating limit in table 4 to this subpart that applies to your EGU.

(b) As provided in § 63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO_2 limit in Tables 1 and 2 to this subpart only if your EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and an SO*2* continuous emissions monitoring system (CEMS) installed on the EGU; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology and the SO*2* CEMS installed on the EGU consistent with § 63.10000(b).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 81 FR 20180, Apr. 6, 2016; 89 FR 38564, May 7, 2024; 91 FR 9114, Feb. 24, 2026]

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements, items 3 and 4, in Table 3 to this subpart during periods of startup or shutdown.

(b) 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. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with § 63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) and (B) of this section:

(A) Except as provided in paragraph (c)(1)(i)(C) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

(C) You may pursue the LEE option provided that:

(*1*) Your EGU's control device bypass emissions are measured in the bypass stack or duct or your control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event; or

(*2*) Except for hours during which only clean fuel is combusted, you bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU's annual operating hours; you use clean fuels to the maximum extent possible during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. You must include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status.

(ii) For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status.

(iii) For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(iv) If your coal-fired or solid oil derived fuel-fired or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO*2*) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO*2* emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(A) You may choose to use separate sorbent trap monitoring systems to comply with this subpart: One sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods.

(B) You may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emissions limit at all times (including startup periods and shutdown periods) and to report average mercury concentration. You must follow the startup or shutdown requirements that follow and as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance through quarterly performance testing and parametric monitoring for HCl and HF. If you choose to use quarterly testing and parametric monitoring, then you must also develop a site-specific monitoring plan that identifies the CMS you will use to ensure that the operations of the EGU remains consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in § 63.10042, then you are not subject to the emission limits in Tables 1 and 2, but you must comply with the performance tune-up work practice requirements in Table 3.

(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of this chapter, and that meet the requirements of § 63.10010. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.

(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of § 63.10010 (e.g., if the CMS was previously certified under another program).

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

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CMS or sorbent trap monitoring system 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). See § 63.10010(a) for further details. For PM CPMS installations, follow the procedures in § 63.10010(h).

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

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of § 63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§ 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with § 63.8(c)(7)(i) where appropriate, and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§ 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to § 63.10021(e).

(f) Except as provided under paragraph (n) of this section, you are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (*e.g.*, 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless your unit is a solid waste incineration unit subject to standards under CAA section 129 (*e.g.*, 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) Except as provided under paragraph (n) of this section, if your unit no longer meets the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that your unit last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h)(1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i)(1) If you own or operate an EGU subject to this subpart and cease to operate in a manner that causes your unit to meet the definition of an EGU subject to this subpart, you must be in compliance with any newly applicable section 112 or 129 standards on the date you selected consistent with paragraphs (g) and (n) of this section.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§ 63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

(l) On or before the date an EGU is subject to this subpart, you must install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(m) Should you choose to rely on paragraph (2) of the definition of “startup” in § 63.10042 for your EGU (only allowed before January 2, 2025), on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the “startup” definition in § 63.10042.

(1) You may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system.

(2) You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(n) If you have permanently converted your EGU from coal or oil to natural gas or biomass after your compliance date (or, if applicable, after your approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents you from operating in a manner that would subject you to this subpart, you are no longer subject to this subpart, notwithstanding the coal or oil usage in the previous calendar years. The date on which you are no longer subject to this subpart is the date on which you converted to natural gas or biomass firing; it is also the date on which you must be in compliance with any newly applicable standards.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013; 79 FR 68788, Nov. 19, 2014; 81 FR 20180, Apr. 6, 2016; 85 FR 55757, Sept. 9, 2020; 89 FR 38564, May 7, 2024; 91 FR 9114, Feb. 24, 2026]

§ 63.10001 [Reserved]

Testing and Initial Compliance Requirements

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (*e.g.*, a heat input-based limit in lb/MMBtu and a gross output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of data, *e.g.*, hourly gross output data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the date in paragraph (f) of this section for tune-up work practices for existing EGUs; the date that compliance must be demonstrated, as given in § 63.9984 for other requirements for existing EGUs; and in paragraph (g) of this section for all requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.*, an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test shall consist of 30- or, if applicable for Hg, 90-boiler operating days. If the CMS is certified prior to the compliance date (or, if applicable, the approved extended compliance date), the test shall begin with the first operating day on or after that date, except as otherwise provided in paragraph (b) of this section. If the CMS

is not certified prior to the compliance date, the test shall begin with the first operating day after certification testing is successfully completed. In all cases, the initial 30- or 90- operating day averaging period must be completed on or before the date that compliance must be demonstrated (*i.e.*, 180 days after the applicable compliance date).

(i) The CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO*2* emissions limit in Table 1 or 2 to this subpart.

(ii) You must collect hourly data from auxiliary monitoring systems (*i.e.*, stack gas flow rate, CO*2*, O*2*, or moisture, as applicable) during the performance test period, in order to convert the pollutant concentrations to units of the standard. If you choose to comply with a gross output-based emission limit, you must also collect hourly gross output data during the performance test period.

(iii) For a group of affected units that are in the same subcategory, are subject to the same emission standards, and share a common stack, if you elect to demonstrate compliance by monitoring emissions at the common stack, startup and shutdown emissions (if any) that occur during the 30-(or, if applicable, 90-) boiler operating day performance test must either be excluded from or included in the compliance demonstration as follows:

(A) If one of the units that shares the stack either starts up or shuts down at a time when none of the other units is operating, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations;

(B) If all units that are currently operating are in the startup or shutdown mode, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations; or

(C) If any unit starts up or shuts down at a time when another unit is operating, and the other unit is not in the startup or shutdown mode, you must include all pollutant emission rates measured during the startup or shutdown period in the compliance demonstrations.

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to § 63.10007 and table 5 to this subpart. Notwithstanding the preceding requirements, when table 5 specifies the use of isokinetic EPA test Method 5, 5D, 5I, 26A, or 29 for a stack test, if concurrent measurement of the stack gas flow rate or moisture content is needed to convert the pollutant concentrations to units of the standard, separate determination of these parameters using EPA test Method 2 or EPA test Method 4 is not necessary. Instead, the stack gas flow rate and moisture content can be determined from data that are collected during the EPA test Method 5, 5D, 5I, 6, 26A, or 29 test (*e.g.*, pitot tube (delta P) readings, moisture collected in the impingers). For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in § 63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in § 63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in § 63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (*e.g.*, stack flow rate, diluent gas concentrations, hourly gross outputs) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(6) For performance stack test data that are collected prior to the date that compliance must be demonstrated and are used to demonstrate initial compliance with applicable emissions limits, the interval for subsequent stack tests begins on the date that compliance must be demonstrated.

(c) *Operating limits.* In accordance with § 63.10010 and table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) *CMS requirements.* If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO*2*, HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an SO*2*, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to this subpart through use of a PM CEMS installed, certified, and operated in accordance with § 63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured

CEMS data, expressed in units of the standard (see § 63.10007(e)), meets the applicable SO*2*, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19-19 of Method 19 in appendix A-7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (**Note:** For this calculation, the term E*hj* in Equation 19-19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the emission limit with which you choose to comply.

(iii) You must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30- (or 90-) boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) *Tune-ups.* All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to § 63.10021(e).

(f) For an existing EGU without a neural network, a tune-up, following the procedures in § 63.10021(e), must occur within 6 months (180 days) after April 16, 2015. For an existing EGU with a neural network, a tune-up must occur within 18 months (545 days) after April 16, 2016. If a tune-up occurs prior to April 16, 2015, you must keep records showing that the tune-up met all rule requirements.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h) and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in § 63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in § 63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30- (or 90-) boiler operating day performance test using Method 30B in appendix A-8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within 10 percent of the duct area centered about the duct's centroid at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30- (or 90-) boiler operating day test period. You may use a pair of sorbent traps to sample the stack gas for a period consistent with that given in section 5.2.1 of appendix A to this subpart. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures). As an alternative to constant rate sampling per Method 30B, you may use proportional sampling per section 8.2.2 of Performance Specification 12 B in appendix B to part 60 of this chapter.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A-3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from § 75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly gross output data (megawatts), from facility records.

(ii) If you use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in $\mu g/m^3$ (dry basis), for each of LEE test runs comprising the 30- (or 90-) boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results from the LEE test period. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and gross output for the LEE test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in § 63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A-3 and A-4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values "C_h", "Q_h", "B_{ws}" and "$(MW)_h$" with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(*1*) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^{-6} to convert it to TBtu/hr; or

(*2*) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^{-3} to convert it to GW; or

(*3*) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (*i.e.*, either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) *Liquid-oil fuel moisture measurement.* If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95-05 (Reapproved 2010), “Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation,” or

(ii) ASTM D4006-11, “Standard Test Method for Water in Crude Oil by Distillation,” including Annex A1 and Appendix A1.

(5) Use one of the following methods to obtain fuel moisture samples:

(i) ASTM D4177-95 (Reapproved 2010), “Standard Practice for Automatic Sampling of Petroleum and Petroleum Products,” including Annexes A1 through A6 and Appendices X1 and X2, or

(ii) ASTM D4057-06 (Reapproved 2011), “Standard Practice for Manual Sampling of Petroleum and Petroleum Products,” including Annex A1.

(6) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in § 63.10030.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013; 79 FR 68789, Nov. 19, 2014; 81 FR 20181, Apr. 6, 2016; 85 FR 55757, Sept. 9, 2020; 89 FR 38565, May 7, 2024; 91 FR 9114, Feb. 24, 2026]

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to table 5 to this subpart and § 63.10007 at least every year.

(b) For affected units meeting the LEE requirements of § 63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and § 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1).

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, you must conduct Hg emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1). You must

have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, § 63.10007, and § 63.10000(c), except as otherwise provided in § 63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO*2* CEMS to monitor compliance with the alternate equivalent SO*2* emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in § 63.10000(c)(2)(iii).

(f) *Time between performance tests.* (1) Notwithstanding the provisions of § 63.10021(d)(1), the requirements listed in paragraphs (g) and (h) of this section, and the requirements of paragraph (f)(3) of this section, you must complete performance tests for your EGU as follows:

(i) At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter;

(ii) For annual testing:

(A) At least 320 calendar days, measured from the test's end date, must separate performance tests;

(B) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests;

(C) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests; and

(iii) At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years.

(2) For units demonstrating compliance through quarterly emission testing, you must conduct a performance test in the 4th quarter of a calendar year if your EGU has skipped performance tests in the first 3 quarters of the calendar year.

(3) If your EGU misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next test period, you must complete an additional performance test in that period as follows:

(i) At least 15 calendar days must separate two performance tests conducted in the same quarter.

(ii) At least 107 calendar days must separate two performance tests conducted in the same calendar year.

(iii) At least 350 calendar days must separate two performance tests conducted in the same 3 year period.

(g) If you elect to demonstrate compliance using emissions averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10021(e).

(1) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 36 calendar months after the previous performance tune-up.

(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 48 calendar months after the previous performance tune-up.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013; 81 FR 20182, Apr. 6, 2016; 89 FR 38565, May 7, 2024; 91 FR 9115, Feb. 24, 2026]

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to § 63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(1) If you use CEMS (Hg, HCl, SO*2*, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, you must collect quality- assured CEMS data for all unit operating conditions, including startup and shutdown

(see § 63.10011(g) and Table 3 to this subpart), except as otherwise provided in § 63.10020(b). Emission rates determined during startup periods and shutdown periods (as defined in § 63.10042) are not to be included in the compliance determinations, except as otherwise provided in §§ 63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non-Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A-7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO_2 ppm by 1.66×10^{-7};

(ii) Multiply HCl ppm by 9.43×10^{-8};

(iii) Multiply HF ppm by 5.18×10^{-8};

(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24×10^{-8}; and

(v) Multiply Hg concentrations (µg/scm) by 6.24×10^{-11}.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A-2 or A-3, replacing the value of K with 1.66×10^{-7} lb/scf-ppm for SO_2, 9.43×10^{-8} lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-8} lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining C_h as the average SO_2, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§ 63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10^3 term from Equation A-4 to determine the pollutant emission rate in lb/MWh.

(f) If you elect to (or are required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default values are available for use in the emission rate

calculations during startup periods or shutdown periods (as defined in § 63.10042). For the purposes of this subpart, these default values are not considered to be substitute data.

(1) *Diluent cap values.* If you use CEMS (or, if applicable, sorbent trap monitoring systems) to comply with a heat input-based emission rate limit, you may use the following diluent cap values for a startup or shutdown hour in which the measured CO_2 concentration is below the cap value or the measured O_2 concentration is above the cap value:

(i) For an IGCC EGU, you may use 1% for CO_2 or 19% for O_2.

(ii) For all other EGUs, you may use 5% for CO_2 or 14% for O_2.

(2) *Default gross output.* If you use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default value is available for use in the emission rate calculations during startup periods or shutdown periods (as defined in § 63.10042). For the purposes of this subpart, this default value is not considered to be substitute data. For a startup or shutdown hour in which there is heat input to an affected EGU but zero gross output, you must calculate the pollutant emission rate using a value equivalent to 5% of the maximum sustainable gross output, expressed in megawatts, as defined in section 6.5.2.1(a)(1) of appendix A to part 75 of this chapter. This default gross output is either the nameplate capacity of the EGU or the highest gross output observed in at least four representative quarters of EGU operation. For a monitored common stack, the default gross output is used only when all EGUs are operating (*i.e.*, combusting fuel) are in startup or shutdown mode, and have zero electrical generation. Under those conditions, a default gross output equal to 5% of the combined maximum sustainable gross output of the EGUs that are operating but have a total of zero gross output must be used to calculate the hourly gross output-based pollutant emissions rate.

(g) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013; 79 FR 68789, Nov. 19, 2014; 81 FR 20182, Apr. 6, 2016; 89 FR 38565, May 7, 2024; 91 FR 9115, Feb. 24, 2026]

§ 63.10008 [Reserved]

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) *General eligibility.* (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of § 63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) *Equations.* Use the following equations when performing calculations for your EGU emissions averaging group:

(1) *Group eligibility equations.*

Variables with the similar names share the descriptions for Equation 1a of this section,

(2) Weighted 30-boiler operating day rolling average emissions rate equations. Use Equation 2a or 2b of this section to calculate the 30 day rolling average emissions daily.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the “coal-fired unit not low rank virgin coal” subcategory. Use Equation 3a or 3b of this section to calculate the 90-day rolling average emissions daily.

Where:

(c) *Separate stack requirements.* For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO*2*, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or

(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the date that you begin emissions averaging.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing your emissions averaging plan, you must conduct required emissions monitoring for 30- (or 90-) days of boiler operation and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with this section. If, before the start of your initial compliance demonstration, the Administrator becomes aware that you intend to use emissions averaging for that demonstration, or if your initial Notification of Compliance Status (NOCS) indicates that you intend to implement emissions averaging at a future date, the Administrator may require you to submit your proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO*2*, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of paragraph (b) of this section as an alternative to using Equation 1a of paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO*2*, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to paragraphs (g)(1) and (2) of this section. The first averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that you begin emissions averaging.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) *CEMS (or sorbent trap monitoring) use.* If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) *Emissions testing.* If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) *Emissions averaging plan.* You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (e.g., CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO_2, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If, as described in paragraph (f) of this section, the Administrator requests you to submit the averaging plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (j)(1) of this section; and

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in § 63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013; 81 FR 20183, Apr. 6, 2016; 85 FR 55757, Sept. 9, 2020]

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork

downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) *Unit(s) utilizing common stack with non-affected unit(s).* (i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) *Unit with a main stack and a bypass stack that exhausts to the atmosphere independent of the main stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack. If it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall:

(i) Route the exhaust from the bypass through the main stack and its monitoring so that bypass emissions are measured; or

(ii) Install a CEMS only on the main stack and count hours that the bypass stack is in use as hours of deviation from the monitoring requirements.

(5) *Unit with a common control device with multiple stack or duct configuration.* If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(6) *Unit with multiple parallel control devices with multiple stacks.* If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(6)(ii) of this section; and

(iv) Divide the result obtained in paragraph (a)(6)(iii) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.*, at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from § 75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f)(1) If you use an SO*2* CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO*2* CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO*2* CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO*2* emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO*2* emission rates in the 30 boiler operating day period.

(4) Use only unadjusted, quality-assured SO*2* concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO*2* data and do not use part 75 substitute data values. For startup or shutdown hours (as defined in § 63.10042) the default gross output and the diluent cap are available for use in the hourly SO*2* emission rate calculations, as described in § 63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default gross output is used to calculate the SO*2* emission rate for any of these hours.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.*, period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (e.g., milliamps, PM concentration, raw data signal).

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data recorded during periods of monitoring system malfunctions or repairs associated with monitoring system malfunctions. You must report any monitoring system malfunctions as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(ii) Any data recorded during periods when the monitoring system is out-of-control (as specified in your site-specific monitoring plan), repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(iii) Any data recorded during required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of output data from the PM CPMS; and

(iv) Any data recorded during periods of startup or shutdown.

(7) You must record and report the results of PM CPMS system performance audits, in accordance with 40 CFR 63.10031(k). You must also record and make available upon request the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record and report the output of the PM CEMS as specified in paragraphs (i)(1) through (8) of this section. Compliance with the applicable PM emissions limit in table 1 or 2 to this subpart is determined on a 30-boiler operating day rolling average basis.

(1) You must install and certify your PM CEMS according to section 4 of appendix C to this subpart.

(2) You must operate, maintain, and quality-assure the data from your PM CEMS according to section 5 of appendix C to this subpart.

(3) You must reduce the data from your PM CEMS to hourly averages in accordance with section 6.1 of appendix C to this subpart.

(4) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for required monitoring system quality assurance or quality control activities and any scheduled maintenance as defined in your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CMS and record the output of the HAP metals CMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install, calibrate, operate, and maintain your HAP metals CMS according to your CMS quality control program, as described in § 63.8(d)(2). The reportable measurement output from the HAP metals CMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for required monitoring system quality assurance or quality control activities, and any scheduled maintenance as defined in your site-specific monitoring plan.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during periods of monitoring system malfunctions and repairs associated with monitoring system malfunctions. You must report any monitoring system malfunctions as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any out of control periods as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(C) Any data recorded during required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (*e.g.*, calibrations, certain audits, routine probe maintenance); and

(D) Any data recorded during periods of startup or shutdown.

(ii) You must record and report the results of HAP metals CMS system performance audits, in accordance with 40 CFR 63.10031(k). You must also record and make available upon request the dates and duration of periods when the HAP metals CMS is out of control to completion of the corrective actions necessary to return the HAP metals CMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in § 63.10000(c)(2)(iii) and Table 7 to this subpart.

(l) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU (only allowed before January 2, 2025), you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the "startup" definition in § 63.10042 for your EGU.

(1) You shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods.

(2) You shall submit the site-specific monitoring plan upon request by the Administrator.

(3) The provisions of the monitoring plan must address the following items:

(i) Monitoring system installation;

(ii) Performance and equipment specifications;

(iii) Schedule for initial and periodic performance evaluations;

(iv) Performance evaluation procedures and acceptance criteria;

(v) On-going operation and maintenance procedures; and

(vi) On-going recordkeeping and reporting procedures.

(4) You may rely on monitoring system specifications or instructions or manufacturer's specifications to address paragraphs (l)(3)(i) through (vi) of this section.

(5) You must operate and maintain the monitoring system according to the site-specific monitoring plan.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013; 79 FR 68789, Nov. 19, 2014; 81 FR 20185, Apr. 6, 2016; 85 FR 55758, Sept. 9, 2020; 89 FR 38565, May 7, 2024; 91 FR 9115, Feb. 24, 2026]

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil fired EGU, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.*, tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.*, Hg or HCl) directly, the initial performance test, shall consist of a 30-boiler operating day (or, for certain coal-fired, existing EGUs that use emissions averaging for Hg, a 90-boiler operating day) rolling average emissions rate obtained with a certified CEMS or sorbent trap system, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 (or, if applicable, 90) boiler operating days prior to that date, as described in § 63.10005(b). In all cases, the initial 30- or 90-boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with § 63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For an EGU that uses a CEMS to measure SO*2* or PM emissions for initial compliance, the initial performance test shall consist of a 30-boiler operating day average emission rate obtained with certified CEMS, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 boiler operating days prior to that date, as described in § 63.10005(b). In all cases, the initial 30- boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with § 63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable SO*2* or PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in § 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status in accordance with 40 CFR 63.10031(f)(4) or (h), as applicable, containing the results of the initial compliance demonstration, as specified in 40 CFR 63.10030(e).

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, *i.e.*, the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements as established in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the emissions data recorded during startup and shutdown. If you are relying on paragraph (2) of the definition of startup in 40 CFR 63.10042 (only allowed before January 2, 2025), then for startup and shutdown incidents that occur on or prior to December 31, 2023, you must also report the applicable supplementary information in 40 CFR 63.10031(c)(5) in the semiannual compliance report. For startup and shutdown incidents that occur on or after January 1, 2024, you must provide the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i).

(4) If you choose to use paragraph (2) of the definition of “startup” in § 63.10042 (only allowed before January 2, 2025), and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of “startup” in § 63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

(i) As mentioned in § 63.6(g)(1), your request will be published in the **Federal Register** for notice and comment rulemaking. Until promulgation in the **Federal Register** of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of “startup” in § 63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the **Federal Register** of the final alternative non-opacity emission standard.

(ii) Your request need not address the items contained in § 63.6(g)(2).

(iii) Your request shall provide evidence of a documented manufacturer-identified safety issue.

(iv) Your request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU.

(v) In addition, your request shall contain documentation that:

(A) Your EGU is using clean fuels to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity, to bring your EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in your EGU;

(B) You have followed explicitly your EGU manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) You have identified with specificity the details of your EGU manufacturer's statement of concern.

(vi) Your request shall specify the other work practice standards you will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule.

(vii) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68790, Nov. 19, 2014; 81 FR 20186, Apr. 6, 2016; 85 FR 55759, Sept. 9, 2020; 89 FR 38566, May 7, 2024; 91 FR 9115, Feb. 24, 2026]

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in your site-specific monitoring plan. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §§ 63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating

levels. You must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system.

(d) 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 excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements.

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU (only allowed before January 2, 2025).

(1) During each period of startup, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of startup begins;

(ii) The quantity and heat input of clean fuel for each hour of startup;

(iii) The gross output for each hour of startup;

(iv) The date and time that non-clean fuel combustion begins; and

(v) The date and time that clean fuels being combusted for the purpose of startup ends.

(2) During each period of shutdown, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of shutdown begins;

(ii) The quantity and heat input of clean fuel for each hour of shutdown;

(iii) The gross output for each hour of shutdown;

(iv) The date and time that non-clean fuel combustion ends; and

(v) The date and time that clean fuels being combusted for the purpose of shutdown ends.

(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10010(l).

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non- liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CMS, you must:

(A) Record temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s), upstream of the filterable PM control devices during each hour of startup.

(B) Record temperature and flow of exhaust gas, as well as amperage of any induced draft fan(s), downstream of the filterable PM control devices during each hour of startup.

(C) For an EGU with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(D) For an EGU with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to flue gas ratio and the pressure drop across the scrubber during each hour of startup.

(ii) [Reserved]

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68790, Nov. 19, 2014; 81 FR 20187, Apr. 6, 2016; 85 FR 55759, Sept. 9, 2020; 89 FR 38567, May 7, 2024; 91 FR 9115, Feb. 24, 2026]

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO*2*, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO*2*, O*2*, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if

alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

Where:

(c) If you use PM CPMS data to measure compliance with an operating limit in table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (*e.g.*, milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use the following equation to determine the 30-boiler operating day average.

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

(i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);

(ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and

(iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and

(3) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired EGU to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020.

(e) Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For your first tune-up, you may perform the burner inspection any time prior to the tune-up or you may delay the first burner inspection until the next scheduled EGU outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO*X* and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO*X* and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O*2* probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO*X*. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO*X* optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO*X* in ppm, by volume, and oxygen in volume percent, before and after the tune-up 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). You may use portable CO, NO*X* and O*2* monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO*X* in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Prior to January 1, 2024, report the tune-up date electronically, in a PDF file, in your semiannual compliance report, as specified in 40 CFR 63.10031(f)(4) and (6) and, if requested by the Administrator, in hard copy, as specified in 40 CFR 63.10031(f)(5). On and after January 1, 2024, report the tune-up date electronically in your quarterly compliance report, in accordance with 40 CFR 63.10031(g) and section 10.2 of appendix E to this subpart. The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed.

(f) You must submit the applicable reports and notifications required under § 63.10031(a) through (k) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) reporting tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS reporting tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS reporting tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to § 63.10031.

(h) You must follow the startup or shutdown requirements as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) [Reserved]

(4) You may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in § 63.10011(g)(4). Until promulgation in the **Federal Register** of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of “startup” in § 63.10042.

(i) Before January 2, 2025, if you are relying on paragraph 2 of the definition of startup in 40 CFR 63.10042, you must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in your semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, you must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013; 79 FR 68791, Nov. 19, 2014; 81 FR 20187, Apr. 6, 2016; 82 FR 16739, Apr. 6, 2017; 83 FR 30883, July 2, 2018; 85 FR 55759, Sept. 9, 2020; 89 FR 38567, May 7, 2024; 91 FR 9115, Feb. 24, 2026]

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of this section.

(1) For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test.

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in table 4 to this subpart that applies.

(4) For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 to this subpart.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68791, Nov. 19, 2014; 89 FR 38567, May 7, 2024; 91 FR 9116, Feb. 24, 2026]

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as provided in paragraph (b)(1) or (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test.

(1) [Reserved]

(2) Determine your operating limit as follows:

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point can also can be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*4*) If none of the steps in paragraphs (A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average (x) in milliamps, and the average of your corresponding three PM compliance test runs (y), using equation 10.

Where:

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

Where:

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

Where:

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.

Where:

(iii) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24086, Apr. 24, 2013; 81 FR 20187, Apr. 6, 2016; 89 FR 38567, May 7, 2024; 91 FR 9116, Feb. 24, 2026]

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed EGU that is an affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the EGU that is an affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). The Notification of Compliance Status report must contain all of the information specified in paragraphs (e)(1) through (8) of this section, that applies to your initial compliance strategy.

(1) A description of the affected source(s), including identification of the subcategory of the source, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (*e.g.*, use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) Except for requests to switch from one emission limit to another, as provided in paragraph (e)(7)(iii) of this section, your initial notification of compliance status shall also include the following information:

(i) [Reserved]

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) “This EGU complies with the requirements in § 63.10021(a) to demonstrate continuous compliance.” and

(B) “No secondary materials that are solid waste were combusted in any affected unit.”

(iii) For each of your existing EGUs, identification of each emissions limit specified in Table 2 to this subpart with which you plan to comply initially. (*Note:* If, at some future date, you wish to switch from the limit specified in your initial notification of compliance status, you must follow the procedures and meet the conditions of paragraphs (e)(7)(iii)(A) through (C) of this section).

(A) You may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:

(*1*) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current and proposed emission limit;

(*2*) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(*3*) Your request includes performance stack test results or valid CMS data, obtained within 45 days prior to the date of your submission, demonstrating that each EGU or EGU emissions averaging group is in compliance with both the mass per heat input limit and the mass per gross output limit;

(*4*) You revise and submit all other applicable plans, *e.g.*, monitoring and emissions averaging, with your request; and

(*5*) You maintain records of all information regarding your choice of emission limits.

(B) You must begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch.

(C) From submission of your request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, you must demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each EGU or EGU emissions averaging group.

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of “startup” in § 63.10042. On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

(i) Before January 2, 2025 should you choose to rely on paragraph (2) of the definition of “startup” in § 63.10042 for your EGU, you shall include a report that identifies:

(A) The original EGU installation date;

(B) The original EGU design characteristics, including, but not limited to, fuel mix and PM controls;

(C) Each design PM control device efficiency established during performance testing or while operating in periods other than startup and shutdown periods;

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour established during performance testing or while operating in periods other than startup and shutdown periods;

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup;

(F) Each design PM control device efficiency upon startup of the PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(G) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls, if different from the characteristics provided in paragraph (e)(8)(i)(B) of this section;

(H) Current PM control device efficiency from each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(I) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour, if different from the rate provided in paragraph (e)(8)(i)(D) of this section;

(J) Current time from start of fuel combustion to conditions necessary for each PM control device startup, if different from the time provided in paragraph (e)(8)(i)(E) of this section; and

(K) Current PM control device efficiency upon startup of each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(H) of this section.

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located.

(iii) You may switch from paragraph (1) of the definition of "startup" in § 63.10042 to paragraph (2) of the definition of "startup" (or vice-versa), provided that:

(A) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current definition of "startup" relied on and the proposed definition you plan to rely on;

(B) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(C) You revise and submit all other applicable plans, *e.g.*, monitoring and emissions averaging, with your submission;

(D) You maintain records of all information regarding your choice of the definition of "startup"; and

(E) You begin to use the revised definition of "startup" in the next reporting period after receipt of written acknowledgement from the Administrator of the switch.

(f) You must submit the notifications in § 63.10000(h)(2) and (i)(2) that may apply to you by the dates specified.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013; 79 FR 68791, Nov. 19, 2014; 81 FR 20187, Apr. 6, 2016; 85 FR 55760, Sept. 9, 2020; 89 FR 38567, May 7, 2024; 91 FR 9116, Feb. 24, 2026]

§ 63.10031 What reports must I submit and when?

(a) You must submit each report in this section that applies to you.

(1) If you are required to (or elect to) monitor Hg emissions continuously, you must meet the electronic reporting requirements of appendix A to this subpart.

(2) If you elect to monitor HCl and/or HF emissions continuously, you must meet the electronic reporting requirements of appendix B to this subpart. Notwithstanding this requirement, if you opt to certify your HCl monitor according to Performance Specification 18 in appendix B to part 60 of this chapter and to use Procedure 6 in appendix F to part 60 of this chapter for on-going QA of the monitor, then, on and prior to December 31, 2023, report only hourly HCl emissions data and the results of daily calibration drift tests and relative accuracy test audits (RATAs) performed on or prior to that date; keep records of all of the other required certification and QA tests and report them, starting in 2024.

(3) If you elect to monitor filterable PM emissions continuously, you must meet the electronic reporting requirements of appendix C to this subpart. Electronic reporting of hourly PM emissions data shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial PM CEMS correlation test.

(4) If you elect to demonstrate continuous compliance using a PM CPMS, you must meet the electronic reporting requirements of appendix D to this subpart. Electronic reporting of the hourly PM CPMS output shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS.

(5) If you elect to monitor SO_2 emission rate continuously as a surrogate for HCl, you must use the ECMPS reporting tool to submit the following information to EPA (except where it is already required to be reported or has been previously provided under the Acid Rain Program or another emissions reduction program that requires the use of part 75 of this chapter):

(i) Monitoring plan information for the SO_2 CEMS and for any additional monitoring systems that are required to convert SO_2 concentrations to units of the emission standard, in accordance with sections 75.62 and 75.64(a)(4) of this chapter;

(ii) Certification, recertification, quality-assurance, and diagnostic test results for the SO_2 CEMS and for any additional monitoring systems that are required to convert SO_2 concentrations to units of the emission standard, in accordance with section 75.64(a)(5); and

(iii) Quarterly electronic emissions reports. You must submit an electronic quarterly report within 30 days after the end of each calendar quarter, starting with a report for the calendar quarter in which the initial 30 boiler operating day performance test begins. Each report must include the following information:

(A) The applicable operating data specified in section 75.57(b) of this chapter;

(B) An hourly data stream for the unadjusted SO_2 concentration (in ppm, rounded to one decimal place), and separate unadjusted hourly data streams for the other parameters needed to convert the SO_2 concentrations to units of the standard. (*Note:* If a default moisture value is used in the emission rate calculations, an hourly data stream is not required for moisture; rather, the default value must be reported in the electronic monitoring plan.);

(C) An hourly SO_2 emission rate data stream, in units of the standard (*i.e.*, lb/MMBtu or lb/MWh, as applicable), calculated according to 40 CFR 63.10007(e) and (f)(1), rounded to the same precision as the emission standard (*i.e.*, with one leading non-zero digit and one decimal place), expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first

decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

(D) The results of all required daily quality-assurance tests of the SO*2* monitor and the additional monitors used to convert SO*2* concentration to units of the standard, as specified in appendix B to part 75 of this chapter; and

(E) A compliance certification, which includes a statement, based on reasonable inquiry of those persons with primary responsibility for ensuring that all SO*2* emissions from the affected EGUs under this subpart have been correctly and fully monitored, by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete. You must submit such a compliance certification statement in support of each quarterly report.

(b) You must submit semiannual compliance reports according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)) and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)).

(2) The first compliance report must be submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)).

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), through the reporting period that ends December 31, 2023, you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(6) The final semiannual compliance report shall cover the reporting period from July 1, 2023, through December 31, 2023. Quarterly compliance reports shall be submitted thereafter, in accordance with paragraph (g) of this section, starting with a report covering the first calendar quarter of 2024.

(c) The semiannual compliance report must contain the information required in paragraphs (c)(1) through (10) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in § 63.10021(e)(6) and (7) were completed.

(5) Should you choose to rely on paragraph (2) of the definition of “startup” in § 63.10042 for your EGU (only allowed before January 2, 2025), for each instance of startup or shutdown you shall:

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of § 63.10032(f).

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of § 63.10020(e).

(iii)—(v) [Reserved]

(6) You must report emergency bypass information annually from EGUs with LEE status.

(7) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If you are conducting stack tests once every 3 years to maintain LEE status, consistent with § 63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in § 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(8) A certification.

(9) If you have a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.

(10) If you had any process or control equipment malfunction(s) during the reporting period, you must include the number, duration, and a brief description for each type of malfunction which occurred during the semiannual reporting period which caused or may have caused any applicable emission limitation to be exceeded.

(d) Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in paragraph (c) of this section must include the excess emissions and monitor downtime summary report described in 40 CFR 63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR 63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and you must, instead, include in the quarterly compliance reports described in paragraph (g) of this section the applicable data elements in section 13 of appendix E to this subpart for any “deviation” (as defined in 40 CFR 63.10042 and elsewhere in this subpart) that occurred during the calendar quarter. If there were no deviations, you must include a statement to that effect in the quarterly compliance report.

(e) Each affected source that has obtained a title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to paragraphs (c) and (d) of this section, or two quarterly compliance reports covering the appropriate calendar half pursuant to paragraph (g) of this section, along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), you must submit a PDF test report in accordance with paragraph (f)(6) of this section, no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR 63.10031(g), submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart along with the quarterly compliance report for the calendar quarter in which the test was completed.

(1) For each RATA of an Hg, HCl, HF, or SO*2* monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, you must submit a PDF test report in accordance with paragraph (f)(6) of this section, no later than 60 days after the date on which the test is completed. For each SO*2* or Hg RATA completed on or after January 1, 2024, you must submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable.

(2) If, for a particular EGU or a group of EGUs serving a common stack, you have elected to demonstrate compliance using a PM CEMS, an approved HAP metals CMS, or a PM CPMS, you must submit quarterly PDF reports in accordance with paragraph (f)(6) of this section, which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in paragraph (g) of this section. In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CMS, the quarterly compliance reports described in paragraph (g) of this section must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO*2*, if you have elected to (or are required to) continuously monitor these pollutants. Further, if your EGU or common stack is in an averaging plan, your quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group.

(3) [Reserved]

(4) You must submit semiannual compliance reports as required under paragraphs (b) through (d) of this section, ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under § 63.10030(e), as PDF files. Quarterly compliance reports shall be submitted in a format specified by the Administrator, thereafter, in accordance with paragraph (g) of this section, starting with a report covering the first calendar quarter of 2024.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f) introductory text and (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.

(6) All reports and notifications described in paragraphs (f) introductory text, (f)(1), (2), and (4) of this section shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS reporting tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The following data elements must be entered into the ECMPS reporting tool at the time of submission of each PDF file:

(i) The facility name, physical address, mailing address (if different from the physical address), and county;

(ii) The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;

(iii) The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;

(iv) If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report the ID number of the common stack as it is represented in the electronic monitoring plan required under § 75.53 of this chapter;

(v) If any of the EGUs described in paragraph (f)(6)(iii) of this section are in an averaging plan under § 63.10009, indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;

(vi) The identification of each emission point to which the report applies. An “emission point” is a point at which source effluent is released to the atmosphere, and is either a dedicated stack that serves one of the EGUs identified in paragraph (f)(6)(iii) of this section or a common stack that serves two or more of those EGUs. To identify an emission point, associate it with the EGU or stack ID in the CAMD Business system or the electronic monitoring plan (*e.g.*, “Unit 2 stack,” “common stack CS001,” or “multiple stack MS001”);

(vii) An indication of the type of PDF report or notification being submitted;

(viii) The pollutant(s) being addressed in the report;

(ix) The reporting period being covered by the report (if applicable);

(x) The relevant test method that was performed for a performance test (if applicable);

(xi) The date the performance test was completed (if applicable) and the test number (if applicable); and

(xii) The responsible official's name, title, and phone number.

(g) Starting with a report for the first calendar quarter of 2024, you must use the ECMPS reporting tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of appendix E to this subpart. For each stack test summarized in the compliance report, you must also submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter.

(h) On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR 63.9(h)(2)(ii), as PDF files, using the ECMPS reporting tool. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into the ECMPS reporting tool with each Notification.

(i) If you have elected to use paragraph (2) of the definition of “startup” in § 63.10042 (only allowed before January 2, 2025), then, for startup and shutdown incidents that occur on or prior to December 31, 2023, you must include the information in § 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If you have elected to use paragraph (2) of the definition of “startup” in § 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you must use the ECMPS reporting tool to submit the information in §§ 63.10031(c)(5) and 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into the ECMPS reporting tool with each startup and shutdown report.

(j) If you elect to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with this subpart and have begun recording valid data from the PM CEMS prior to November 9, 2020, you must use the ECMPS reporting tool to submit a detailed report of your PS 11 correlation test (see appendix B to part 60 of this chapter) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, you must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, you must submit the PDF report according to section 7.2.4 of appendix C to this subpart. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into the ECMPS reporting tool with the PDF report.

(k) If you elect to demonstrate compliance using a PM CPMS or an approved HAP metals CMS, you must submit quarterly reports of your QA/QC activities (*e.g.*, calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CMS is used for the compliance demonstration in that quarter. Otherwise, submit a report for the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into the ECMPS reporting tool with the PDF report.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68791, Nov. 19, 2014; 79 FR 68799, Nov. 19, 2014; 80 FR 15514, Mar. 24, 2015; 81 FR 20188, Apr. 6, 2016; 82 FR 16739, Apr. 6, 2017; 83 FR 30883, July 2, 2018; 85 FR 55760, Sept. 9, 2020; 89 FR 38568, May 7, 2024; 91 FR 9116, Feb. 26, 2026]

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if you elect to use a PM CPMS, you must keep the records required under appendix A and/or appendix B and/or appendix C and/or appendix D to this subpart. If you elect to conduct periodic (*e.g.*, quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, you must keep records of the applicable data elements under 40 CFR 63.7(g). You must also keep records of all data elements and other information in appendix E to this subpart that apply to your compliance strategy.

(1) In accordance with 40 CFR 63.10(b)(2)(xiv), a copy of each notification or report that you submit to comply with this subpart. You must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit.

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under § 63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) Regarding startup periods or shutdown periods:

(1) Should you choose to rely on paragraph (1) of the definition of “startup” in § 63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown.

(2) Should you choose to rely on paragraph (2) of the definition of “startup” in § 63.10042 for your EGU (on or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042), you must keep records of:

(i) The determination of the maximum possible clean fuel capacity for each EGU;

(ii) The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and

(iii) The information required in § 63.10020(e).

(g) You must keep records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.

[77 FR 9464, Feb. 16, 2012, as amended at 79 FR 68792, Nov. 19, 2014; 81 FR 20189, Apr. 6, 2016; 85 FR 55763, Sept. 9, 2020; 89 FR 38568, May 7, 2024; 91 FR 9117, Feb. 24, 2026]

§ 63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority 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 (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if 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 listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of “test method” in § 63.2.

(3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.10042 What definitions apply to this subpart?

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

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.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see § 63.14).

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see § 63.14).

Boiler operating day means a 24-hour period that begins at midnight and ends the following midnight during which any fuel is combusted at any time in the EGU, excluding startup periods or shutdown periods. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Clean fuel means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) fuel, including those fuels meeting the requirements of part 1090, subpart D of this chapter.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered “coal” for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

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

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of “fossil fuel-fired” or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

Default electrical load means an electrical load equal to 5 percent of the maximum sustainable electrical output (megawatts), as defined in section 6.5.2.1(a)(1) of Appendix A to part 75 of this chapter, of an affected EGU that is in startup or shutdown mode. For monitored common stack configurations, the default electrical load is 5 percent of the combined maximum sustainable electrical load of the EGUs that are in startup or shutdown mode during an hour in which the electrical load for all operating EGUs is zero. The default electrical load is used to calculate the electrical output-based emission rate (lb/MWh or lb/GWh, as applicable) for any startup or shutdown hour in which the actual electrical load is zero. The default electrical load is not used for EGUs required to make heat input-based emission rate (lb/MMBtu or lb/TBtu, as applicable) calculations. For the purposes of this subpart, the default electrical load is not considered to be a substitute data value.

Deviation. (1) *Deviation* 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 requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; 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. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Diluent cap means a default CO*2* or O*2* concentration that may be used to calculate the Hg, HCl, HF, PM, or SO*2* emission rate (lb/MMBtu or lb/TBtu, as applicable) during a startup or shutdown hour in which the measured CO*2* concentration is below the cap value or the measured O*2* concentration is above the cap value. The appropriate diluent cap values for EGUs are presented in § 63.10007(f) and in section 6.2.1.2 of Appendix A to this subpart. For the purposes of this subpart, the diluent cap is not considered to be a substitute data value.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Dry flue gas desulfurization technology, or *dry FGD,* or *spray dryer absorber* (*SDA*), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO*2* and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (e.g., conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO*2* and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Eastern bituminous coal refuse (EBCR) means coal refuse generated from the mining of bituminous coal in Pennsylvania and West Virginia.

Electric Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) 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 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; 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.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO*2* in the exhaust gas stream.

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

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of producing more than 25 MW of electrical output from the combustion of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit 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 means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

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

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler,* or *CFB* means a boiler utilizing a fluidized bed combustion process.

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 upward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years in a combined-cycle gas turbine. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. No solid coal or solid oil-derived fuel is directly burned in the unit during operation. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see § 63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor when burning oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing on the first of the month following the compliance date specified in § 63.9984.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction means 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.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Net summer capacity means the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

Neural network or *neural net* for purposes of this rule means an automated boiler optimization system. A neural network typically has the ability to process data from many inputs to develop, remember, update, and enable algorithms for efficient boiler operation.

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

Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

Out-of-control period, as it pertains to continuous monitoring systems, means any period:

(1) Beginning with the hour corresponding to the completion of a daily calibration or quality assurance audit that indicates that the instrument fails to meet the applicable acceptance criteria; and

(2) Ending with the hour corresponding to the completion of an additional calibration or quality assurance audit following corrective action showing that the instrument meets the applicable acceptance criteria.

Particulate matter or *PM* means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Responsible official means responsible official as defined in 40 CFR 70.2.

Shutdown means the period in which cessation of operation of an EGU is initiated for any purpose. Shutdown begins when the EGU no longer generates electricity or makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes or when no coal, liquid oil, syngas, or solid oil-derived fuel is being fired in the EGU, whichever is earlier. Shutdown ends when the EGU no longer generates electricity or makes useful thermal energy (such as steam or heat) for industrial, commercial, heating, or cooling purposes, and no fuel is being fired in the EGU. Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown.

Startup means:

(1) The first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup.

(2) Alternatively, prior to January 2, 2025, the period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

Stationary 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 stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Unit designed for coal ≥8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

Unit designed for eastern bituminous coal refuse (EBCR) subcategory means any existing (*i.e.,* construction was commenced on or before May 3, 2011) coal-fired EGU with a net summer capacity of no greater than 150 MW that is designed to burn and that is burning 75 percent or more (by heat input) eastern bituminous coal refuse on a 12-month rolling average basis.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. 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 an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or *wet FGD, or wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO*2* and HCl.

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

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23405, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013; 79 FR 68792, Nov. 19, 2014; 81 FR 20189, Apr. 6, 2016; 85 FR 20850, Apr. 15, 2020; 85 FR 55763, Sept. 9, 2020; 89 FR 38568, May 7, 2024; 91 FR 9117, Feb. 24, 2026; 91 FR 16482, Apr. 1, 2026]

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits:

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	**For the following pollutants . . .**	**You must meet the following emission limits and work practice standards . . .**	**Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in table 5 to this subpart . . .**
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh 1	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	

	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010) 2 or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) 3	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh 1	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348-03 (Reapproved 2010) 2 or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) 3	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E-2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	7.0E-2 lb/MWh 4 9.0E-2 lb/MWh 5	Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh	
	Arsenic (As)	2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	

	Chromium (Cr)	4.0E-2 lb/GWh	
	Cobalt (Co)	4.0E-3 lb/GWh	
	Lead (Pb)	9.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	7.0E-2 lb/GWh	
	Selenium (Se)	3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 2 or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) 3	4.0E-1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-1 lb/MWh 1	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E-4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E-2 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	5.0E-4 lb/GWh	
	Cadmium (Cd)	2.0E-4 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-2 lb/GWh	
	Lead (Pb)	8.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	9.0E-2 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	1.0E-4 lb/GWh	For Method 30B at appendix A-8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010) 2 or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010) 2 or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	2.0E-1 lb/MWh 1	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	6.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	

	Cobalt (Co)	3.0E-1 lb/GWh	
	Lead (Pb)	3.0E-2 lb/GWh	
	Manganese (Mn)	1.0E-1 lb/GWh	
	Nickel (Ni)	4.1E0 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 2 or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010) 2 or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	3.0E-2 lb/MWh 1	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	7.0E-4 lb/GWh	
	Chromium (Cr)	6.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	7.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	6.0E-3 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010) 2 or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) 3	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E-3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

1 Gross output.

2 Incorporated by reference, see § 63.14.

3 You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.

4 Duct burners on syngas; gross output.

5 Duct burners on natural gas; gross output.

[81 FR 20190, Apr. 6, 2016, as amended at 89 FR 38569, May 7, 2024; 91 FR 9117, Feb. 24, 2026]

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits: [1]

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits 1]

If your EGU is in this subcategory . . .	**For the following pollutants . . .**	**You must meet the following emission limits and work practice standards . . .**	**Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in table 5 to this subpart . . .**
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh 2	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 3 or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) 4	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E-2 lb/GWh	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh 2	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance demonstration. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	

	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 3 or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) 4	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh 2	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-1 lb/TBtu or 1.0E-3 lb/GWh	
	Cadmium (Cd)	1.5E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	
	Nickel (Ni)		

		6.5E0 lb/TBtu or 7.0E-2 lb/GWh	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 3 or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh 2	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E-1 lb/GWh	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E-2 lb/GWh	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 1.0E-2 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 3 or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MMBtu or 4.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 3 or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh 2	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E-4 lb/MMBtu or 7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)		

		2.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E-2 lb/GWh	
	Beryllium (Be)	6.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E-1 lb/GWh	
	Mercury (Hg)	4.0E-2 lb/TBtu or 4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 3 or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010) 3 or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh 2	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 7.0E-3 lb/GWh	
	Arsenic (As)	3.0E-1 lb/TBtu or 5.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-2 lb/TBtu or 5.0E-4 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 4.0E-3 lb/GWh	
	Chromium (Cr)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E-1 lb/GWh	
	Selenium (Se)	1.2E0 lb/Tbtu or 2.0E-2 lb/GWh	

	b. Hydrogen chloride (HCl)	5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 3 or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) 4	3.0E-1 lb/MMBtu or 2.0E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
7. Eastern Bituminous Coal Refuse (EBCR)-fired unit	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh 2	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010) 3 or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) 4	6E-1 lb/MMBtu or 9E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E-2 lb/GWh	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

1 For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of 2.

2 Gross output.

3 Incorporated by reference, *see* § 63.14.

4 You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

[85 FR 20850, Apr. 15, 2020, as amended at 89 FR 38571, May 7, 2024; 91 FR 9117, Feb. 24, 2026]

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

As stated in §§ 63.9991, you must comply with the following applicable work practice standards:

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup	a. Before January 2, 2025 you have the option of complying using either of the following work practice standards in paragraphs (1) and (2). On or after January 2, 2025 you may not choose to use paragraph (2) of the definition of startup in § 63.10042 and the following associated work practice standards in paragraph (2).
	(1) If you choose to comply using paragraph (1) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i).
	(2) If you choose to comply using paragraph (2) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup.
	For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e).
	Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your PM control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel.
	You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart that require operation of the control devices.
	b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.
	c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods.
	d. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10021(h) and 63.10032. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart and that require operation of the control devices.

	If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.
	Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.
	You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

[81 FR 20196, Apr. 6, 2016, as amended at 85 FR 55763, Sept. 9, 2020; 89 FR 38580, May 7, 2024]

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

As stated in § 63.9991, you must comply with the applicable operating limits:

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

[As stated in § 63.9991, you must comply with the applicable operating limits]

If you demonstrate compliance using . . .	**You must meet these operating limits . . .**
PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

[81 FR 20197, Apr. 6, 2016, as amended at 89 FR 38582, May 7, 2024; 91 FR 9117, Feb. 26, 2026]

Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources: [1]

Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources 1]

To conduct a performance test for the following pollutant . . .	**Using . . .**	**You must perform the following activities, as applicable to your input- or output-based emission limit . . .**	**Using . . . 2**
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. 3
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Methods 5 or 5I at appendix A-3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 or 5I front half temperature shall be 160° ± 14 °C (320° ± 25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS		

		a. Install, certify, operate, and maintain the PM CEMS	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ ASME PTC 19.10-1981. 3
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	Method 29 at appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ ASME PTC 19.10-1981. 3
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations	Method 26 or Method 26A at appendix A-8 to part 60 of this chapter or Method 320 at appendix A to part 63 of this chapter or ASTM D6348-03 3 with
			(1) the following conditions when using ASTM D6348-03:
			(A) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);
			(C) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and
			(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation: Reported Result = (Measured Concentration in Stack)/(%R)x100.
			(2) Spiking levels nominally no greater than two times the level corresponding to the applicable emission limit.
			Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).

		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ ASME PTC 19.10-1981. 3
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter, ASTM D6784 3 or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/ GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ ASME PTC 19.10-1981, 3 or diluent gas monitoring systems certified according to part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.*, per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and § 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).

		c. Convert hourly emissions concentrations to 30-boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).

1 Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h).

2 See tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

3 Incorporated by reference, see § 63.14.

[88 FR 18415, Mar. 29, 2023, as amended at 89 FR 38582, May 7, 2024; 91 FR 9117, Feb. 24, 2026; 91 FR 20369, Apr. 16, 2026]

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

As stated in § 63.10007, you must comply with the following requirements for establishing operating limits:

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	**And you choose to establish PM CPMS operating limits, you must . . .**	**And . . .**	**Using . . .**	**According to the following procedures . . .**
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1)	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.*, milliamps, mg/acm, or other raw signal)	Data from the PM CPMS and the PM or HAP metals performance tests	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

[81 FR 20201, Apr. 6, 2016, as amended at 89 FR 38590, May 7, 2024; 91 FR 9117, Feb. 24, 2026]

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	**You demonstrate continuous compliance by . . .**
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (*e.g.*, milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in table 2	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with table 3.
	Operating in accordance with table 3.

7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown	

[78 FR 24092, Apr. 24, 2013, as amended at 89 FR 38590, May 7, 2024; 91 FR 9117, Feb. 24, 2026]

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

[In accordance with § 63.10031, you must meet the following reporting requirements, as they apply to your compliance strategy]

You must submit the following reports . . .
1. The electronic reports required under § 63.10031 (a)(1), if you continuously monitor Hg emissions.
2. The electronic reports required under § 63.10031 (a)(2), if you continuously monitor HCl and/or HF emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
3. The electronic reports required under § 63.10031(a)(3), if you continuously monitor PM emissions.
Reporting of hourly PM emissions data using ECMPS shall begin with the first operating hour after: January 1, 2024, or the hour of completion of the initial PM CEMS correlation test, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
4. The electronic reports required under § 63.10031(a)(4), if you elect to use a PM CPMS.
Reporting of hourly PM CPMS response data using ECMPS shall begin with the first operating hour after January 1, 2024, or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
5. The electronic reports required under § 63.10031(a)(5), if you continuously monitor SO_2 emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
6. PDF reports for all performance stack tests completed prior to January 1, 2024 (including 30- or 90-boiler operating day Hg LEE test reports and PM test reports to set operating limits for PM CPMS), according to § 63.10031(f) introductory text and (f)(6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For a PM test that is used to set an operating limit for a PM CPMS, the report must also include the information in § 63.10023(b)(2)(vi).
For each performance stack test completed on or after January 1, 2024, submit the test results in the relevant quarterly compliance report under § 63.10031(g), together with the applicable reference method information in sections 17 through 31 of appendix E to this subpart.
7. PDF reports for all RATAs of Hg, HCl, HF, and/or SO_2 monitoring systems completed prior to January 1, 2024, and for correlation tests, RRAs and/or RCAs of PM CEMS completed prior to January 1, 2024, according to § 63.10031(f)(1) and (6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For each SO_2 or Hg system RATA completed on or after January 1, 2024, submit the electronic test summary required by appendix A to this subpart or part 75 of this chapter (as applicable) together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart, either prior to or concurrent with the relevant quarterly emissions report.
For each HCl or HF system RATA, and for each correlation test, RRA, and RCA of a PM CEMS completed on or after January 1, 2024, submit the electronic test summary in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable, together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart.
8. Quarterly reports, in PDF files, that include all 30-boiler operating day rolling averages in the reporting period derived from your PM CEMS, approved HAP metals CMS, and/or PM CPMS, according to § 63.10031(f)(2) and (6). These reports are due no later than 60 days after the end of each calendar quarter.
The final quarterly rolling averages report in PDF files shall cover the fourth calendar quarter of 2023.
Starting with the first quarter of 2024, you must report all 30-boiler operating day rolling averages for PM CEMS, approved HAP metals CMS, PM CPMS, Hg CEMS, Hg sorbent trap systems, HCl CEMS, HF CEMS, and/or SO_2 CEMS (or 90-boiler operating day rolling averages for Hg systems), in a format specified by the Administrator, in the quarterly compliance reports required under § 63.10031(g).
If your EGU or common stack is in an averaging plan, each quarterly compliance report must identify the EGUs in the plan and include all of the 30- or 90-group boiler operating day WAERs for the averaging group.
The quarterly compliance reports must be submitted no later than 60 days after the end of each calendar quarter.
9. The semiannual compliance reports described in § 63.10031(c) and (d), in PDF files, according to § 63.10031(f)(4) and (6). The due dates for these reports are specified in § 63.10031(b).
The final semiannual compliance report shall cover the period from July 1, 2023, through December 31, 2023.
10. Notifications of compliance status, in PDF files, according to § 63.10031(f)(4) and (6) until December 31, 2023, and according to § 63.10031(h) thereafter.
11. Quarterly electronic compliance reports, in accordance with § 63.10031(g), starting with a report for the first calendar quarter of 2024. The reports must be in a format specified by the Administrator and must include the applicable data elements in sections 2 through 13 of appendix E to this subpart.
These reports are due no later than 60 days after the end of each calendar quarter.

12. Quarterly reports, in PDF files, that include the applicable information in §§ 63.10031(c)(5)(ii) and 63.10020(e) pertaining to startup and shutdown events, starting with a report for the first calendar quarter of 2024, if you have elected to use paragraph 2 of the definition of startup in § 63.10042 (see § 63.10031(i)). On or after January 2, 2025, you may not use paragraph 2 of the definition of startup in § 63.10042.
These PDF reports shall be submitted no later than 60 days after the end of each calendar quarter, along with the quarterly compliance reports required under § 63.10031(g).
13. A test report for the PS 11 correlation test of your PM CEMS, in accordance with § 63.10031(j).
If, prior to November 9, 2020, you have begun using a certified PM CEMS to demonstrate compliance with this subpart, use the ECMPS reporting tool to submit the report, in a PDF file, no later than 60 days after that date.
For correlation tests completed on or after November 9, 2020, but prior to January 1, 2024, submit the report, in a PDF file, no later than 60 days after the date on which the test is completed.
For correlation tests completed on or after January 1, 2024, submit the test results electronically, according to section 7.2.4 of appendix C to this subpart, together with the applicable reference method data in sections 17 through 31 of appendix E to this subpart.
14. Quarterly reports that include the QA/QC activities for your PM CPMS or approved HAP metals CMS (as applicable), in PDF files, according to § 63.10031(k).
The first report shall cover the first calendar quarter of 2024, if the PM CPMS or HAP metals CMS is in use during that quarter. Otherwise, reporting begins with the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance.
These reports are due no later than 60 days after the end of each calendar quarter.

[85 FR 55764, Sept. 9, 2020, as amended at 89 FR 38591, May 7, 2024; 91 FR 9117, Feb. 24, 2026]

Table 9 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1) through (5), (b)(7), (c), (f)(2) and (3), (h)(2) through (9), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(g)	Compliance with Standards and Maintenance Requirements, Use of an alternative non-opacity emission standard	Yes. See §§ 63.10011(g)(4) and 63.10021(h)(4) for additional requirements.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes, except (1) for the 60-day notification prior to conducting a performance test in § 63.9(e); instead use a 30-day notification period per § 63.10030(d), (2) the notification of the CMS performance evaluation in § 63.9(g)(1) is limited to RATAs, and (3) the information required per § 63.9(h)(2)(i); instead provide the applicable information in § 63.10030(e)(1) through (8), for the initial notification of compliance status, only.
		Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).

§ 63.10(a), (b)(1), (c), (d)(1) and (2), (e), and (f)	Recordkeeping and Reporting Requirements	
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) through (ix)	Other CMS requirements	Yes.
§ 63.10(b)(3) and (d)(3) through (5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS — identifying exceedances and excess emissions	Applies only through December 31, 2023.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS— identifying exceedances and excess emissions	Applies only through December 31, 2023.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See § 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.10(e)(3)(v) and (vi)	Excess emissions and CMS performance reports	Applies only through December 31, 2023.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§§ 63.13 through 63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§§ 63.1(a)(5),(a)(7) through (9), (b)(2), (c)(3) and (4), (d), 63.6(b)(6), (c)(3) and (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) through (4), (c)(9).	Reserved	No.

[81 FR 20202, Apr. 6, 2016, as amended at 85 FR 55765, Sept. 9, 2020]

Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (e.g., lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, § 63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.*, when the system is "in control". However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 *Redundant Backup Systems.* A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on "hot standby" in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 *Non-redundant Backup Monitoring Systems.* A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on "cold standby" and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 *Temporary Like-kind Replacement Analyzers.* When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix "LK".

2.2.4 *Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.* To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (*i.e.*, sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg^0, CAS Number 7439-97-6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg + *2* to Hg ^{0} converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (µg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST-Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators" or an interim version of that protocol.

3.1.5 *NIST-Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride (HgCl*2*), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (*i.e.*, low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit* or *RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 *Quality Assurance (QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon ™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg *+2* to Hg ^{0} converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 *Sample Probe.* The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A-1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A-1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and HgCl*2* separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this appendix), and including, but not limited to, Hg gas generators and Hg gas cylinders, shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg ^{0} and HgCl*2* are required. Special reagents and equipment may be needed to prepare the Hg ^{0} and HgCl*2* gas standards (*e.g.,* NIST-traceable solutions of HgCl*2* and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (*i.e.*, a flow monitor, CO_2 or O_2 monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 µg/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 µg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (*i.e.*, the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 µg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 µg/scm; or the next highest multiple of 10 µg/scm.

3.2.1.4.3 *Analyzer Range.* The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Data Collection.* To convert measured hourly Hg concentrations to the units of the applicable emissions standard (*i.e.*, lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§ 63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (*i.e.*, in lb/TBtu), data from a certified CO_2 or O_2 monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (*i.e.*, lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Sorbent Trap Monitoring System Operation.* Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in § 63.9984(f).

4.1.1 *Hg CEMS.* Table A-1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (*i.e.*, combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in paragraphs 3.1.8, 3.1.10, and 3.1.11 of this appendix). Use a NIST-traceable elemental Hg gas standard (as defined in paragraphs 3.1.4 of this appendix) for the test. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. If moisture is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over non-consecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.*, resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A-1 of this appendix. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A-1. The LE must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A-1 of this appendix. The SIE must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

Table A-1—Required Certification Tests and Performance Specifications for H*g* CEMS

For this required certification test . . .	**The main performance specification 1 is . . .**	**The alternate performance specification 1 is . . .**	**And the conditions of the alternate specification are . . .**
7-day calibration error test 2 6	|R − A| ≤ 5.0% of span value, for both the zero and upscale gases, on each of the 7 days.	|R − A| ≤ 1.0 µg/scm	The alternate specification may be used on any day of the test.
Linearity check 3 6	|R − A*avg* | ≤ 10.0% of the reference gas concentration at each calibration gas level (low, mid, or high).	|R − A*avg* | ≤ 0.8 µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check 4	|R − A*avg* | ≤ 10.0% of the reference gas concentration at each calibration gas level.	|R − A*avg* | ≤ 0.8 µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	|RM*avg* − C*avg*| + |CC| ≤ 0.5 µg/scm 7	RM*avg* < 2.5µg/scm
Cycle time test 5	15 minutes where the stability criteria are readings change by < 2.0% of span *or* by ≤ 0.5 µg/scm, for 2 minutes.		

1 Note that |R − A| is the absolute value of the difference between the reference gas value and the analyzer reading. |R − A*avg*| is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

2 Use elemental Hg standards; a mid-level or high-level upscale gas may be used.

3 Use elemental Hg standards.

4 Use oxidized Hg standards.

5 Use elemental Hg standards; a high-level upscale gas must be used. The cycle time test is not required for Hg CEMS that use integrated batch sampling; however, those monitoring systems must be capable of recording at least one Hg concentration reading every 15 minutes.

6 If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

7 Note that |RM*avg* − C*avg*| is the absolute difference between the mean reference method value and the mean CEMS value from the RATA; CC is the confidence coefficient from Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter.

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784-16 (IBR, see § 63.14) and methods 29, 30A, and 30B in appendix A-8 to part 60 of this chapter. When method 29 or ASTM D6784-16 is used, paired sampling trains are required, and the filterable portion of the sample need not be included when making comparisons to the Hg CEMS results for purposes of a RATA. To validate a method 29 or ASTM D6784-16 test run, calculate the relative deviation (RD) using equation A-1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

4.1.1.5.1 *Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if method 30A is used. If method 29, method 30B, or ASTM D6784-16 is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when method 29 or ASTM D6784-162 is used, in which case, up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2—3 through 2-6 of PS 2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 “The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 µg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 µg/dscm and >0.5 µg/dscm, ≤20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 µg/dscm and >0.1 µg/dscm, ≤50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1µg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry.The main and alternative RATA performance specifications in Table A-1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *Hg CEMS.*

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A-2, below. All tests must be performed with the affected unit(s) operating (*i.e.*, combusting fuel), however, the daily calibration may optionally be performed off-line. The RATA must be performed at normal load, but no particular load level is required for the other tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use a NIST-traceable elemental Hg gas standard for these calibrations. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for “non-QA operating quarters”. A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 Perform a single-level system integrity check weekly, *i.e.*, once every 7 operating days (see the third column in Table A-2 of this appendix).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.*, once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 *Grace Periods.*

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A-2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 *Conditional Data Validation.* For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

Table A-2—On-Going QA Test Requirements for H*g* CEMS

Perform this type of QA test . . .	**At this frequency . . .**	**With these qualifications and exceptions . . .**	**Acceptance criteria . . .**
Calibration error test 5	Daily	• Use either a mid- or high-level gas • Use elemental Hg • Calibrations are not required when the unit is not in operation.	|R − A| ≤ 5.0% of span value *or* |R − A| ≤ 1.0 µg/scm.
Single-level system integrity check	Weekly 1	• Use oxidized Hg—either mid- or high-level	|R − A*avg*| ≤ 10.0% of the reference gas value *or* |R − A*avg*| ≤ 0.8 µg/scm.
Linearity check *or* 3-level system integrity check	Quarterly 3	• Required in each "QA operating quarter" 2 and no less than once every 4 calendar quarters • 168 operating hour grace period available • Use elemental Hg for linearity check • Use oxidized Hg for system integrity check	|R − A*avg* | ≤ 10.0% of the reference gas value, at each calibration gas level *or* |R − A*avg*| ≤ 0.8 µg/scm.
RATA	Annual 4	• Test deadline may be extended for "non-QA operating quarters," up to a maximum of 8 quarters from the quarter of the previous test • 720 operating hour grace period available	≤20.0% RA *or* |*RM*avg − *C*avg | + |CC| ≤ 0.5 µg/scm, if RM_{avg} < 2.5 µg/scm.

1 "Weekly" means once every 7 operating days.

2 A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.

3 "Quarterly" means once every QA operating quarter.

4 "Annual" means once every four QA operating quarters.

5 If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

5.1.6 *Adjustment of Span.* If you discover that a span adjustment is needed (e.g., if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B-1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 15 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, *i.e.*, once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A-2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B-1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§ 63.10010(b) through (d)).

5.4 *QA/QC Program Requirements.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the

program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (e.g., changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B-1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.*, flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24×10^{-11} to convert it from µg/scm to lb/scf. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average O_2 concentration is above 14.0% O_2 (19.0% for an IGCC) or the hourly average CO_2 concentration is below 5.0% CO_2 (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10^{6} to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation 19-19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E_{hj} in Equation 19-19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A-2 of this section (for wet-basis measurements of Hg concentration) or Equation A-3 of this section (for dry-basis measurements), as applicable:

Where:

(**Note:** Use unadjusted flow rate values; bias adjustment is not required)

Where:

6.2.2.2 Use Equation A-4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

Where:

6.2.2.3 The applicable gross output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30- (or 90-) boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation A-5 of this appendix to calculate the Hg emission rate for each averaging period.

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and any other monitoring system(s) (*i.e.*, flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under § 75.53 (g) of this chapter.

7.1.1.2.1 *Electronic.* The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; emissions controls; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; and Hg monitor span and range information. The electronic monitoring plan shall be evaluated and submitted using the ECMPS reporting tool provided by the EPA.

7.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records.* The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.2.5 If applicable, a flag to indicate that the hour is a startup or shutdown hour (as defined in § 63.10042).

7.1.2.6 The EGUs that constitute an emissions averaging group.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, with one leading non-zero digit and one decimal place, expressed in scientific notation). Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, with one leading non-zero digit and one decimal place, expressed in scientific notation). Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged. Note that when a single quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, e.g., liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from § 75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

7.1.7 *Records of Diluent Gas (CO2* or O*2*) Concentration.

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO*2* or O*2* concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO*2* or O*2* monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO*2* or O*2* concentration records, as specified in § 75.57(g) of this chapter.

7.1.8 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable), calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to the same precision as the standard (*i.e.*, with one leading non-zero digit and one decimal place, expressed in scientific notation), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A-4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.8.5 If applicable, a code to indicate that the default gross output (as defined in § 63.10042) was used to calculate the Hg emission rate.

7.1.8.6 If applicable, a code to indicate that the diluent cap (as defined in § 63.10042) was used to calculate the Hg emission rate.

7.1.9 *Certification and Quality Assurance Test Records.* For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;

7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B-1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with § 63.10030.

7.2.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 For an EGU that begins reporting hourly Hg concentrations with a previously-certified Hg monitoring system, submit the monitoring plan information in section 7.1.1.2 of this appendix prior to or concurrent with the first required quarterly emissions report. For a new EGU, or for an EGU switching to continuous monitoring of Hg emissions after having implemented another allowable compliance option under this subpart, submit the information in section 7.1.1.2 of this appendix at least 21 days prior to the start of initial certification testing of the CEMS. Also submit the monitoring plan information in section 75.53(g) pertaining to any required flow rate, diluent gas, and moisture monitoring systems within the applicable time frame specified in this section, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS reporting tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

7.2.4 *Certification, Recertification, and Quality-Assurance Test Reporting.* Except for daily QA tests of the required monitoring systems (*i.e.,* calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.9.1 through 7.1.9.7 of this section (except for test results previously submitted, *e.g.,* under the ARP) shall be submitted electronically, using the ECMPS reporting tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.9984, the owner or operator of any affected unit shall use the ECMPS reporting tool to submit electronic quarterly reports to the Administrator, in a format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.9.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23408, Apr. 19, 2012; 78 FR 24093, Apr. 24, 2013; 79 FR 68795, Nov. 19, 2014; 81 FR 20203 Apr. 6, 2016; 82 FR 16740, Apr. 6, 2017; 85 FR 55766, Sept. 9, 2020; 88 FR 18422, Mar. 29, 2023; 88 FR 24339, Apr. 20, 2023; 91 FR 9130, Feb. 24 2026]

Appendix B to Subpart UUUUU of Part 63—-HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with § 63.10010(a) and either Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems or Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter for HCl CEMS.

2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *Monitoring System Equipment, Supplies, Definitions, and General Operation.*

The following provisions apply:

2.3.1 PS 15, Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 of appendix B to part 60 of this chapter; or

2.3.2 PS 18, Sections 3.0, 6.0, and 11.0 of appendix B to part 60 of this chapter.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 If you choose to follow PS 15 of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below.

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (*i.e.*, independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are

Methods 26 and 26A in appendix A-8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348-03 (Reapproved 2010) “Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy” (incorporated by reference, see § 63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348-03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≤R ≤130%; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 If you choose to follow PS 18 of appendix B to part 60 of this chapter, then your HCl CEMS must be certified according to PS 18, sections 7.0, 8.0, 11.0, 12.0, and 13.0.

3.3 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

On-going QA test requirements for HCl and HF CEMS must be implemented as follows:

5.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then the quality assurance/ quality control procedures of PS 15 shall apply as set forth in sections 5.1.1 through 5.1.3 and 5.4.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ±5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, “quarterly” means once every “QA operating quarter” (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for “non-QA operating quarters” (*i.e.*, calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.4.2.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, “annual” means once every four “QA operating quarters” (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 If you choose to follow Performance Specification PS 18 of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures in Procedure 6 of appendix F to part 60 of this chapter shall apply. The quarterly and annual QA tests required under Procedure 6 shall be performed, respectively, at the frequencies specified in sections 5.1.2 and 5.1.3 of this appendix.

5.3 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3.1 *Out-of-Control Periods.* A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 *Grace Periods.* For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.3 *Conditional Data Validation* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

5.4 *Data Validation.*

5.4.1 *Out-of-Control Periods.* An HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.4.2 *Grace Periods.* For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.4.2.1 For the monitoring systems described in section 5.3 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.4.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an HCl CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.4.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit or other quarterly data accuracy assessment; or

5.4.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.4.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.4.2.3.1 For a gas audit or RATA of the monitoring systems described in sections 5.1 and 5.2 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.4.2.3.2 For the gas audit or other quarterly data accuracy assessment of an HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.4.2.3.3 For the RATA of an HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.4.3 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, the conditional data validation provisions in § 75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a quarterly gas audit or data accuracy assessment shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for HCl and HF CEMS.*

8.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 *Specific Requirements for HCl and HF CEMS.* The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with § 60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in Appendix A-7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by 9.43×10^{-8} to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is 5.18×10^{-8}. The appropriate diluent cap value from section 6.2.1.2 of Appendix A to this subpart may be used to calculate the HCl or HF emission rate (lb/MMBtu) during startup or shutdown hours.

9.3.2 For gross output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A-2 or A-3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-8} (for HF) and defining C*h* as the hourly average HCl or HF concentration in ppm. Then, divide the result by the hourly gross output (megawatts) to convert it to units of lb/MWh. If the gross output is zero during a startup or shutdown hour, use the default gross output (as defined in § 63.10042) to calculate the HCl or HF emission rate. The default gross output is not considered to be a substitute data value.

9.4 Use Equation A-5 in appendix A of this subpart to calculate the required 30-boiler operating day rolling average HCl or HF emission rates. Report each 30-boiler operating day rolling average to the same precision as the standard (*i.e.,* with one leading non-zero digit and one decimal place), expressed in scientific notation. The term E*ho* in Equation A-5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (*i.e,* flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 *Contents of the Monitoring Plan.* For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53(g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS reporting tool.

10.1.1.2.1 *Electronic.* Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (*i.e.,* CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 *Operating Parameter Records.* For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.2.5 If applicable, a flag to indicate that the hour is a startup or shutdown hour (as defined in § 63.10042).

10.1.3 *HCl and/or HF Emissions Records.* For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), with one leading non-zero digit and one decimal place, expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

10.1.4 *Stack Gas Volumetric Flow Rate Records.*

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.*, lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

10.1.5 *Records of Stack Gas Moisture Content.*

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter.

10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from § 75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

10.1.6 *Records of Diluent Gas (CO2 or O2) Concentration.*

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO*2* or O*2* concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO*2* or O*2* monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO*2* or O*2* concentration records, as specified in § 75.57(g) of this chapter.

10.1.7 *HCl and HF Emission Rate Records.* For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, or lb/MWh, as applicable), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour. Round off the emission rate to the same precision as the standard (*i.e.*, with one leading non-zero digit and one decimal place, expressed in scientific notation). Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.7.5 If applicable, a code to indicate that the default electrical load (as defined in § 63.10042) was used to calculate the HCl or HF emission rate.

10.1.7.6 If applicable, a code to indicate that the diluent cap (as defined in § 63.10042) was used to calculate the HCl or HF emission rate.

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For each required 7-day and daily calibration drift test or daily calibration error test (including daily calibration transfer standard tests) of the HCl or HF CEMS, record the test date(s) and time(s), reference gas value(s), monitor response(s), and calculated calibration drift or calibration error value(s). If you use the dynamic spiking option for the mid-level calibration drift check under PS-18, you must also record the measured concentration of the native HCl in the flue gas before and after the spike and the spiked gas dilution factor. When using an IP-CEMS under PS-18, you must also record the measured concentrations of the native HCl before and after introduction of each reference gas, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the instrument line strength factor, and the calculated equivalent concentration of reference gas.

10.1.8.1.2 For the required gas audits of an FTIR HCl or HF CEMS that is following PS 15, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each required RATA of an HCl or HF CEMS, record the beginning and ending date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS run values. Keep records of stratification tests performed (if any), all of the raw field data, relevant process operating data, and all of the calculations used to determine the relative accuracy.

10.1.8.1.4 For each required beam intensity test of an HCl IP-CEMS under PS-18, record the test date and time, the known attenuation value (%) used for the test, the concentration of the high-level reference gas used, the full-beam and attenuated beam intensity levels, the measured HCl concentrations at full-beam intensity and attenuated intensity and the percent difference between them, and the results of the test. For each required daily beam intensity check of an IP-CEMS under Procedure 6, record the beam intensity measured including the units of measure and the results of the check.

10.1.8.1.5 For each required measurement error (ME) test of an HCl monitor, record the date and time of each gas injection, the reference gas concentration (low, mid, or high) and the monitor response for each of the three injections at each of the three levels. Also record the average monitor response and the ME at each gas level and the related calculations. For ME tests conducted on IP-CEMS, also record the measured concentrations of the native HCl before and after introduction of each reference gas, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the calculated equivalent concentration of reference gas.

10.1.8.1.6 For each required level of detection (LOD) test of an HCl monitor performed in a controlled environment, record the test date, the concentrations of the reference gas and interference gases, the results of the seven (or more) consecutive measurements of HCl, the standard deviation, and the LOD value. For each required LOD test performed in the field, record the test date, the three measurements of the native source HCl concentration, the results of the three independent standard addition (SA) measurements known as standard addition response (SAR), the effective spike addition gas concentration (for IP-CEMS, the equivalent concentration of the reference gas), the resulting standard addition detection level (SADL) value and all related calculations. For extractive CEMS performing the SA using dynamic spiking, you must record the spiked gas dilution factor.

10.1.8.1.7 For each required ME/level of detection response time test of an HCl monitor, record the test date, the native HCl concentration of the flue gas, the reference gas value, the stable reference gas readings, the upscale/downscale start and end times, and the results of the upscale and downscale stages of the test.

10.1.8.1.8 For each required temperature or pressure measurement verification or audit of an IP-CEMS, keep records of the test date, the temperatures or pressures (as applicable) measured by the calibrated temperature or pressure reference device and the IP-CEMS, and the results of the test.

10.1.8.1.9 For each required interference test of an HCl monitor, record (or obtain from the analyzer manufacturer records of): The date of the test; the gas volume/rate, temperature, and pressure used to conduct the test; the HCl concentration of the reference gas used; the concentrations of the interference test gases; the baseline HCl and HCl responses for each interferent combination spiked; and the total percent interference as a function of span or HCl concentration.

10.1.8.1.10 For each quarterly relative accuracy audit (RAA) of an HCl monitor, record the beginning and ending date and time of each test run, the reference method used, the HCl concentrations measured by the reference method and CEMS for each test run, the average concentrations measured by the reference method and the CEMS, and the calculated relative accuracy. Keep records of the raw field data, relevant process operating data, and the calculations used to determine the relative accuracy.

10.1.8.1.11 For each quarterly cylinder gas audit (CGA) of an HCl monitor, record the date and time of each injection, and the reference gas concentration (zero, mid, or high) and the monitor response for each injection. Also record the average monitor response and the calculated ME at each gas level. For IP-CEMS, you must also record the measured concentrations of the native HCl before and after introduction of each reference gas, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the calculated equivalent concentration of reference gas.

10.1.8.1.12 For each quarterly dynamic spiking audit (DSA) of an HCl monitor, record the date and time of the zero gas injection and each spike injection, the results of the zero gas injection, the gas concentrations (mid and high) and the dilution factors and the monitor response for each of the six upscale injections as well as the corresponding native HCl concentrations measured before and after each injection. Also record the average dynamic spiking error for each of the upscale gases, the calculated average DSA Accuracy at each upscale gas concentration, and all calculations leading to the DSA Accuracy.

10.1.8.2 *Additional Monitoring Systems.* For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59(a) of this chapter.

11. Reporting Requirements

11.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with § 63.10030.

11.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 For an EGU that begins reporting hourly HCl and/or HF concentrations with a previously-certified CEMS, submit the monitoring plan information in section 10.1.1.2 of this appendix prior to or concurrent with the first required quarterly emissions report. For a new EGU, or for an EGU switching to continuous monitoring of HCl and/or HF emissions after having implemented another allowable compliance option under this subpart, submit the information in section 10.1.1.2 of this appendix at least 21 days prior to the start of initial certification testing of the CEMS. Also submit the monitoring plan information in section 75.53(g) pertaining to any required flow rate, diluent gas, and moisture monitoring systems within the applicable time frame specified in this section, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS reporting tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*i.e.*, calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS reporting tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically. Submit the test results either prior to or concurrent with the relevant quarterly electronic emissions report. However, for RATAs of the HCl monitor, if this is not possible, you have up to 60 days after the test completion date to submit the test results; in this case, you may claim provisional status for the emissions data affected by the test, starting from the date and hour in which the test was completed and continuing until the date and hour in which the test results are submitted. If the test is successful, the status of the data in that time period changes from provisional to quality-assured, and no further action is required. However, if the test is unsuccessful, the provisional data must be invalidated and resubmission of the affected emission report(s) is required.

11.4.1 For each daily calibration drift (or calibration error) assessment (including daily calibration transfer standard tests), and for each 7-day calibration drift test of an HCl or HF monitor, report:

11.4.1.1 Facility ID information;

11.4.1.2 The monitoring component ID;

11.4.1.3 The instrument span and span scale;

11.4.1.4 For each gas injection, the date and time, the calibration gas level (zero, mid or other), the reference gas value (ppm), and the monitor response (ppm);

11.4.1.5 A flag to indicate whether dynamic spiking was used for the upscale value (extractive HCl monitors only);

11.4.1.6 Calibration drift or calibration error (percent of span or reference gas, as applicable);

11.4.1.7 When using the dynamic spiking option, the measured concentration of native HCl before and after each mid-level spike and the spiked gas dilution factor;

11.4.1.8 When using an IP-CEMS, also report the measured concentration of native HCl before and after each upscale measurement, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the equivalent concentration of the reference gas; and

11.4.1.9 Reason for test (for the 7-day CD test, only).

11.4.2 For each quarterly gas audit of an HCl or HF CEMS that is following PS 15, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (e.g., quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (*i.e.*, initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, using either Equation 2-4 in section 12.3 of PS 2 in appendix B to part 60 of this chapter or Equation 10 in section 12.6.5 of PS 18;

11.4.3.12 Confidence coefficient, using either Equation 2-5 in section 12.4 of PS 2 in appendix B to part 60 of this chapter or Equation 11 in section 12.6.6 of PS 18;

11.4.3.13 t-value; and

11.4.3.14 Relative accuracy calculated using Equation 2-6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 For each 3-level ME test of an HCl monitor, report:

11.4.4.1 Facility ID information;

11.4.4.2 Monitoring component ID;

11.4.4.3 Instrument span and span scale;

11.4.4.4 For each gas injection, the date and time, the calibration gas level (low, mid, or high), the reference gas value in ppm and the monitor response. When using an IP-CEMS, also report the measured concentration of native HCl before and after each injection, the path

lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the equivalent concentration of the reference gas;

11.4.4.5 For extractive CEMS, the mean reference value and mean of measured values at each reference gas level (ppm). For IP-CEMS, the mean of the measured concentration minus the average measured native concentration minus the equivalent reference gas concentration (ppm), at each reference gas level—see Equation 6A in PS 18;

11.4.4.6 ME at each reference gas level; and

11.4.4.7 Reason for test.

11.4.5 Beam intensity tests of an IP CEMS:

11.4.5.1 For the initial beam intensity test described in PS 18 in appendix B to part 60 of this chapter, report:

11.4.5.1.1 Facility ID information;

11.4.5.1.2 Date and time of the test;

11.4.5.1.3 Monitoring system ID;

11.4.5.1.4 Reason for test;

11.4.5.1.5 Attenuation value (%);

11.4.5.1.6 High level gas concentration (ppm);

11.4.5.1.7 Full and attenuated beam intensity levels, including units of measure;

11.4.5.1.8 Measured HCl concentrations at full and attenuated beam intensity (ppm); and

11.4.5.1.9 Percentage difference between the HCl concentrations.

11.4.5.2 For the daily beam intensity check described in Procedure 6 of appendix F to Part 60 of this chapter, report:

11.4.5.2.1 Facility ID information;

11.4.5.2.2 Date and time of the test;

11.4.5.2.3 Monitoring system ID;

11.4.5.2.4 The attenuated beam intensity level (limit) established in the initial test;

11.4.5.2.5 The beam intensity measured during the daily check; and

11.4.5.2.6 Results of the test (pass or fail).

11.4.6 For each temperature or pressure verification or audit of an HCl IP-CEMS, report:

11.4.6.1 Facility ID information;

11.4.6.2 Date and time of the test;

11.4.6.3 Monitoring system ID;

11.4.6.4 Type of verification (temperature or pressure);

11.4.6.5 Stack sensor measured value;

11.4.6.6 Reference device measured value;

11.4.6.7 Results of the test (pass or fail); and

11.4.6.8 Reason for test.

11.4.7 For each interference test of an HCl monitoring system, report:

11.4.7.1 Facility ID information;

11.4.7.2 Date of test;

11.4.7.3 Monitoring system ID;

11.4.7.4 Results of the test (pass or fail);

11.4.7.5 Reason for test; and

11.4.7.6 A flag to indicate whether the test was performed: On this particular monitoring system; on one of multiple systems of the same type; or by the manufacturer on a system with components of the same make and model(s) as this system.

11.4.8 For each LOD test of an HCl monitor, report:

11.4.8.1 Facility ID information;

11.4.8.2 Date of test;

11.4.8.3 Reason for test;

11.4.8.4 Monitoring system ID;

11.4.8.5 A code to indicate whether the test was done in a controlled environment or in the field;

11.4.8.6 HCl reference gas concentration;

11.4.8.7 HCl responses with interference gas (seven repetitions);

11.4.8.8 Standard deviation of HCl responses;

11.4.8.9 Effective spike addition gas concentrations;

11.4.8.10 HCl concentration measured without spike;

11.4.8.11 HCl concentration measured with spike;

11.4.8.12 Dilution factor for spike;

11.4.8.13 The controlled environment LOD value (ppm or ppm-meters);

11.4.8.14 The field determined standard addition detection level (SADL in ppm or ppm-meters); and

11.4.8.15 Result of LDO/SADL test (pass/fail).

11.4.9 For each ME or LOD response time test of an HCl monitor, report:

11.4.9.1 Facility ID information;

11.4.9.2 Date of test;

11.4.9.3 Monitoring component ID;

11.4.9.4 The higher of the upscale or downscale tests, in minutes; and

11.4.9.5 Reason for test.

11.4.10 For each quarterly RAA of an HCl monitor, report:

11.4.10.1 Facility ID information;

11.4.10.2 Monitoring system ID;

11.4.10.3 Begin and end time of each test run;

11.4.10.4 The reference method used;

11.4.10.5 The reference method and CEMS values for each test run, including the units of measure;

11.4.10.6 The mean reference method and CEMS values for the three test runs;

11.4.10.7 The calculated relative accuracy, percent; and

11.4.10.8 Reason for test.

11.4.11 For each quarterly cylinder gas audit of an HCl monitor, report:

11.4.11.1 Facility ID information;

11.4.11.2 Monitoring component ID;

11.4.11.3 Instrument span and span scale;

11.4.11.4 For each gas injection, the date and time, the reference gas level (zero, mid, or high), the reference gas value in ppm, and the monitor response. When using an IP-CEMS, also report the measured concentration of native HCl before and after each injection, the path lengths of the calibration cell and the stack optical path, the stack and calibration cell temperatures, the stack and calibration cell pressures, the instrument line strength factor, and the equivalent concentration of the reference gas;

11.4.11.5 For extractive CEMS, the mean reference gas value and mean monitor response at each reference gas level (ppm). For IP-CEMS, the mean of the measured concentration minus the average measured native concentration minus the equivalent reference gas concentration (ppm), at each reference gas level -see Equation 6A in PS 18;

11.4.11.6 ME at each reference gas level; and

11.4.11.7 Reason for test.

11.4.12 For each quarterly DSA of an HCl monitor, report:

11.4.12.1 Facility ID information;

11.4.12.2 Monitoring component ID;

11.4.12.3 Instrument span and span scale;

11.4.12.4 For the zero gas injection, the date and time, and the monitor response (*Note:* The zero gas injection from a calibration drift check performed on the same day as the upscale spikes may be used for this purpose.);

11.4.12.5 Zero spike error;

11.4.12.6 For the upscale gas spiking, the date and time of each spike, the reference gas level (mid- or high-), the reference gas value (ppm), the dilution factor, the native HCl concentrations before and after each spike, and the monitor response for each gas spike;

11.4.12.7 Upscale spike error;

11.4.12.8 DSA at the zero level and at each upscale gas level; and

11.4.12.9 Reason for test.

11.4.13 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.8.2 of this appendix.

11.5 *Quarterly Reports.*

11.5.1 The owner or operator of any affected unit shall use the ECMPS reporting tool to submit electronic quarterly reports to the Administrator in a format specified by the Administrator, for each affected unit (or group of units monitored at a common stack). If the certified HCl or HF CEMS is used for the initial compliance demonstration, HCl or HF emissions reporting shall begin with the first operating hour of the 30-boiler operating day compliance demonstration period. Otherwise, HCl or HF emissions reporting shall begin with the first operating hour after successfully completing all required certification tests of the CEMS.

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24094, Apr. 24, 2013; 79 FR 68795, Nov. 19, 2014; 81 FR 20205, Apr. 6, 2016; 85 FR 55766, Sept. 9, 2020; 91 FR 9131, Feb. 24, 2026]

Appendix C to Subpart UUUUU of Part 63—PM Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the continuous measurement of filterable PM emissions from affected EGUs under this subpart. A PM CEMS is used together with other CMS and (as applicable) parametric measurement devices to quantify PM emissions in units of the applicable standard (*i.e.*, lb/MMBtu or lb/MWh).

1.2 *Initial Certification and Recertification Procedures.* You, as the owner or operator of an affected EGU that uses a PM CEMS to demonstrate compliance with a filterable PM emissions limit in table 1 or 2 to this subpart must certify and, if applicable, recertify the CEMS according to Performance Specification 11 (PS-11) in appendix B to part 60 of this chapter.

1.3 *Quality Assurance and Quality Control Requirements.* You must meet the applicable quality assurance requirements of Procedure 2 in appendix F to part 60 of this chapter.

1.4 *Missing Data Procedures.* You must not substitute data for missing data from the PM CEMS. Any process operating hour for which quality-assured PM concentration data are not obtained is counted as an hour of monitoring system downtime.

1.5 *Adjustments for Flow System Bias.* When the PM emission rate is reported on a gross output basis, you must not adjust the data recorded by a stack gas flow rate monitor for bias, which may otherwise be required under section 75.24 of this chapter.

2. Monitoring of PM Emissions

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected EGUs under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, 40 CFR 63.10010(a) specifies the appropriate location(s) at which to install CMS. These CMS installation provisions apply to the PM CEMS and to the other CMS and parametric monitoring devices that provide data for the PM emissions calculations in section 6 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7 of this appendix, you must create and designate a primary monitoring system for PM and for each additional parameter (*i.e.*, stack gas flow rate, CO_2 or O_2 concentration, stack gas moisture content, as applicable). The primary system must be used to report hourly PM concentration values when the system is able to provide quality-assured data, *i.e.*, when the system is "in control." However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate a redundant backup monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location and is kept on "hot standby" in case the primary monitoring system is unable to provide quality-assured data. You must represent each redundant backup system as a unique monitoring system in the electronic monitoring plan. You must certify each redundant backup monitoring system according to the applicable provisions in section 4 of this appendix. In addition, each redundant monitoring system must meet the applicable on-going QA requirements in section 5 of this appendix.

3. PM Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable

3.1 *Definitions.* All definitions specified in section 3 of PS-11 in appendix B to part 60 of this chapter and section 3 of Procedure 2 in appendix F to part 60 of this chapter are applicable to the measurement of filterable PM emissions from electric utility steam generating units under this subpart. In addition, the following definitions apply:

3.1.1 *Stack operating hour* means a clock hour during which flue gases flow through a particular stack or duct (either for the entire hour or for part of the hour) while the associated unit(s) are combusting fuel.

3.1.2 *Unit operating hour* means a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.2 *Continuous Monitoring Methods.*

3.2.1 Installation and Measurement Location. You must install the PM CEMS according to 40 CFR 63.10010 and Section 2.4 of PS-11.

3.2.2 Units of Measure. For the purposes of this subpart, you shall report hourly PM concentrations in units of measure that correspond to your PM CEMS correlation curve (*e.g.*, mg/acm, mg/acm @ 160 °C, mg/wscm, mg/dscm).

3.2.3 Other Necessary Data Collection. To convert hourly PM concentrations to the units of the applicable emissions standard (*i.e.*, lb/MMBtu or lb/MWh), you must collect additional data as described in sections 3.2.3.1 and 3.2.3.2 of this appendix. You must install, certify, operate, maintain, and quality-assure any stack gas flow rate, CO_2, O_2, or moisture monitoring systems needed for this purpose according to sections 4 and 5 of this appendix. The calculation methods for the emission limits described in sections 3.2.3.1 and 3.2.3.2 of this appendix are presented in section 6 of this appendix.

3.2.3.1 Heat Input-Based Emission Limits. To demonstrate compliance with a heat input-based PM emission limit in Table 2 to this subpart, you must provide the hourly stack gas CO_2 or O_2 concentration, along with a fuel-specific F_c factor or dry-basis F-factor and (if applicable) the stack gas moisture content, in order to convert measured PM concentrations values to the units of the standard.

3.2.3.2 Gross Output-Based Emission Limits. To demonstrate compliance with a gross output-based PM emission limit in Table 1 or Table 2 to this subpart, you must provide the hourly gross output in megawatts, along with data from a certified stack gas flow rate monitor and (if applicable) the stack gas moisture content, in order to convert measured PM concentrations values to units of the standard.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* You must certify your PM CEMS and the other CMS used to determine compliance with the applicable emissions standard before the PM CEMS can be used to provide data under this subpart. Redundant backup monitoring systems (if used) are subject to the same certification requirements as the primary systems.

4.1.1 PM CEMS. You must certify your PM CEMS according to PS-11 in appendix B to part 60 of this chapter. A PM CEMS that has been installed and certified according to PS-11 as a result of another state or federal regulatory requirement or consent decree prior to the effective date of this subpart shall be considered certified for this subpart if you can demonstrate that your PM CEMS meets the acceptance criteria in PS-11 and Procedure 2 in appendix F to part 60 of this chapter.

4.1.1.1 [RESERVED]

4.1.2 Flow Rate, Diluent Gas, and Moisture Monitoring Systems. You must certify the continuous monitoring systems that are needed to convert PM concentrations to units of the standard or (if applicable) to convert the measured PM concentrations from wet basis to dry basis or vice-versa (*i.e.*, stack gas flow rate, diluent gas (CO_2 or O_2) concentration, or moisture monitoring systems), in accordance with the applicable provisions in section 75.20 of this chapter and appendix A to part 75 of this chapter.

4.1.3 Other Parametric Measurement Devices. Any temperature or pressure measurement devices that are used to convert hourly PM concentrations to standard conditions must be installed, calibrated, maintained, and operated according to the manufacturers' instructions.

4.2 *Recertification.*

4.2.1 You must recertify your PM CEMS if it is either: moved to a different stack or duct; moved to a new location within the same stack or duct; modified or repaired in such a way that the existing correlation is altered or impacted; or replaced.

4.2.2 The flow rate, diluent gas, and moisture monitoring systems that are used to convert PM concentration to units of the emission standard are subject to the recertification provisions in section 75.20(b) of this chapter.

4.2.3 [RESERVED]

4.3 *Development of a New or Revised Correlation Curve.* You must develop a new or revised correlation curve if:

4.3.1 An RCA is failed and the new or revised correlation is developed according to section 10.6 in Procedure 2 of appendix F to part 60 of this chapter; or

4.3.2 The events described in paragraph (1) or (2) in section 8.8 of PS-11 occur.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *PM CEMS.*

5.1.1 Required QA Tests. Following initial certification, you must conduct periodic QA testing of each primary and (if applicable) redundant backup PM CEMS. The required QA tests and the criteria that must be met are found in Procedure 2 of appendix F to part 60 of this chapter (Procedure 2). Except as otherwise provided in section 5.1.2 of this appendix, the QA tests shall be done at the frequency specified in Procedure 2.

5.1.2 RRA and RCA Test Frequencies.

5.1.2.1 The test frequency for RRAs of the PM CEMS shall be annual, *i.e.,* once every 4 calendar quarters. The RRA must either be performed within the fourth calendar quarter after the calendar quarter in which the previous RRA was completed or in a grace period (see section 5.1.3, below). When a required annual RRA is done within a grace period, the deadline for the next RRA is 4 calendar quarters after the quarter in which the RRA was originally due, rather than the calendar quarter in which the grace period test is completed.

5.1.2.2 The test frequency for RCAs of the PM CEMS shall be triennial, *i.e.,* once every 12 calendar quarters. If a required RCA is not completed within 12 calendar quarters after the calendar quarter in which the previous RCA was completed, it must be performed in a grace period immediately following the twelfth calendar quarter (see section 5.1.3, below). When an RCA is done in a grace period, the deadline for the next RCA shall be 12 calendar quarters after the calendar quarter in which the RCA was originally due, rather than the calendar quarter in which the grace period test is completed.

5.1.2.3 Successive quarterly audits (*i.e.,* ACAs and, if applicable, sample volume audits (SVAs)) shall be conducted at least 60 days apart.

5.1.3 Grace Period. A grace period is available, immediately following the end of the calendar quarter in which an RRA or RCA of the PM CEMS is due. The length of the grace period shall be the lesser of 720 EGU (or stack) operating hours or 1 calendar quarter.

5.1.4 RCA and RRA Acceptability. The results of your RRA or RCA are considered acceptable provided that the criteria in section 10.4(5) of Procedure 2 in appendix F to part 60 of this chapter are met for an RCA or section 10.4(6) of Procedure 2 in appendix F to part 60 of this chapter are met for an RRA.

5.1.5 Data Validation. Your PM CEMS is considered to be out-of-control, and you may not report data from it as quality-assured, when, for a required certification, recertification, or QA test, the applicable acceptance criterion (either in PS-11 in appendix B to part 60 of this chapter or Procedure 2 in appendix F to part 60 of this chapter) is not met. Further, data from your PM CEMS are considered out-of-control, and may not be used for reporting, when a required QA test is not performed on schedule or within an allotted grace period. When an out-of-control period occurs, you must perform the appropriate follow-up actions. For an out-of-control period triggered by a failed QA test, you must perform and pass the same type of test in order to end the out-of-control period. For a QA test that is not performed on time, data from the PM CEMS remain out-of-control until the required test has been performed and passed. You must count all out-of-control data periods of the PM CEMS as hours of monitoring system downtime.

5.2 *Stack Gas Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements and data validation criteria for the primary and (if applicable) redundant backup stack gas flow rate, diluent gas, and moisture monitoring systems are specified in appendix B to part 75 of this chapter.

5.3 *QA/QC Program Requirements.* You must develop and implement a QA/QC program for the PM CEMS and the other equipment that is used to provide data under this subpart. You may store your QA/QC plan electronically, provided that the information can be made available expeditiously in hard copy to auditors and inspectors.

5.3.1 General Requirements.

5.3.1.1 Preventive Maintenance. You must keep a written record of the procedures needed to maintain the PM CEMS and other equipment that is used to provide data under this subpart in proper operating condition, along with a schedule for those procedures. At a minimum, you must include all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.3.1.2 Recordkeeping Requirements. You must keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.3.1.3 Maintenance Records. You must keep a record of all testing, maintenance, or repair activities performed on the PM CEMS, and other equipment used to provide data under this subpart in a location and format suitable for inspection. You may use a maintenance log for this purpose. You must maintain the following records for each system or device: The date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed, and records of any corrective actions taken. Additionally, you must record any adjustment that may affect the ability of a monitoring system or measurement device to make accurate measurements, and you must keep a written explanation of the procedures used to make the adjustment(s).

5.3.2 Specific Requirements for the PM CEMS.

5.3.2.1 Daily, and Quarterly Quality Assurance Assessments. You must keep a written record of the procedures used for daily assessments of the PM CEMS. You must also keep records of the procedures used to perform quarterly ACA and (if applicable) SVA audits. You must document how the test results are calculated and evaluated.

5.3.2.2 Monitoring System Adjustments. You must document how each component of the PM CEMS will be adjusted to provide correct responses after routine maintenance, repairs, or corrective actions.

5.3.2.3 Correlation Tests, Annual and Triennial Audits. You must keep a written record of procedures used for the correlation test(s), annual RRAs, and triennial RCAs of the PM CEMS. You must document how the test results are calculated and evaluated.

5.3.3 Specific Requirements for Diluent Gas, Stack Gas Flow Rate, and Moisture Monitoring Systems. The QA/QC program requirements for the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.3.4 Requirements for Other Monitoring Equipment. For the equipment required to convert readings from the PM CEMS to standard conditions (*e.g.*, devices to measure temperature and pressure), you must keep a written record of the calibrations and/or other procedures used to ensure that the devices provide accurate data.

5.3.5 You may store your QA/QC plan electronically, provided that you can make the information available expeditiously in hard copy to auditors or inspectors.

6. Data Reduction and Calculations

6.1 *Data Reduction and Validation.*

6.1.1 You must reduce the data from PM CEMS to hourly averages, in accordance with 40 CFR 60.13(h)(2) of this chapter.

6.1.2 You must reduce all CEMS data from stack gas flow rate, CO_2, O_2, and moisture monitoring systems to hourly averages according to 40 CFR 75.10(d)(1) of this chapter.

6.1.3 You must reduce all other data from devices used to convert readings from the PM CEMS to standard conditions to hourly averages according to 40 CFR 60.13(h)(2) or 40 CFR 75.10(d)(1) of this chapter. This includes, but is not limited to, data from devices used to measure temperature and pressure, or, for cogeneration units that calculate gross output based on steam characteristics, devices to measure steam flow rate, steam pressure, and steam temperature.

6.1.4 Do not calculate the PM emission rate for any unit or stack operating hour in which valid data are not obtained for PM concentration or for any parameter used in the PM emission rate calculations (*i.e.*, gross output, stack gas flow rate, stack temperature, stack pressure, stack gas moisture content, or diluent gas concentration, as applicable).

6.1.5 For the purposes of this appendix, part 75 substitute data values for stack gas flow rate, CO_2 concentration, O_2 concentration, and moisture content are not considered to be valid data.

6.1.6 Operating hours in which PM concentration is missing or invalid are hours of monitoring system downtime. The use of substitute data for PM concentration is not allowed.

6.1.7 You must exclude all data obtained during a boiler startup or shutdown operating hour (as defined in 40 CFR 63.10042) from the determination of the 30-boiler operating day rolling average PM emission rates.

6.2 *Calculation of PM Emission Rates.* Unless your PM CEMS is correlated to provide PM concentrations at standard conditions, you must use the calculation methods in sections 6.2.1 through 6.2.3 of this appendix to convert measured PM concentration values to units of the emission limit (lb/MMBtu or lb/MWh, as applicable).

6.2.1 PM concentrations must be at standard conditions in order to convert them to units of the emissions limit. If your PM CEMS measures PM concentrations at standard conditions, proceed to section 6.2.2 or 6.2.3, below (as applicable). However, if your PM CEMS measures PM concentrations in units of mg/acm or mg/acm at a specified temperature (*e.g.*, 160 °C), you must first use one of the following equations to convert the hourly PM concentration values from actual to standard conditions:

or

6.2.2.2 You must use the appropriate carbon-based or dry-basis F-factor in the emission rate equation that you have selected. You may either use an F-factor from Table 19-2 of EPA test Method 19 in appendix A-7 to part 60 of this chapter or from section 3.3.5 or section 3.3.6 of appendix F to part 75 of this chapter.

6.2.2.3 If the hourly average O*2* concentration is above 14.0% O*2* (19.0% for an IGCC) or the hourly average CO*2* concentration is below 5.0% CO*2* (1.0% for an IGCC), you may calculate the PM emission rate using the applicable diluent cap value (as defined in 40 CFR 63.10042 and specified in 40 CFR 63.10007(f)(1)), provided that the diluent gas monitor is operating and recording quality-assured data).

6.2.2.4 If your selected EPA test Method 19 equation requires a correction for the stack gas moisture content, you may either use quality-assured hourly data from a certified part 75 moisture monitoring system, a fuel-specific default moisture value from 40 CFR 75.11(b) of this chapter, or a site-specific default moisture value approved by the Administrator under section 75.66 of this chapter.

6.2.3 Gross Output-Based PM Emission Rates. For each unit or stack operating hour, if C*std* is measured on a wet basis, you must use Equation C-3 to calculate the gross output-based PM emission rate (if applicable). Use Equation C-4 if C*std* is measured on a dry basis:

or

6.2.4 You must calculate the 30-boiler operating day rolling average PM emission rates according to 40 CFR 63.10021(b).

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* For the PM CEMS and the other necessary CMS and parameter measurement devices installed at each affected unit or common stack, you must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with 40 CFR 63.10033. The file shall contain the applicable information in sections 7.1.1 through 7.1.11 of this appendix.

7.1.1 Monitoring Plan Records. For each EGU or group of EGUs monitored at a common stack, you must prepare and maintain a monitoring plan for the PM CEMS and the other CMS(s) needed to convert PM concentrations to units of the applicable emission standard.

7.1.1.1 Updates. If you make a replacement, modification, or change in a certified CEMS that is used to provide data under this appendix (including a change in the automated data acquisition and handling system (DAHS)) or if you make a change to the flue gas handling system and that replacement, modification, or change affects information reported in the monitoring plan (*e.g.*, a change to a serial number for a component of a monitoring system), you shall update the monitoring plan.

7.1.1.2 Contents of the Monitoring Plan. For the PM CEMS, your monitoring plan shall contain the applicable information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix. For required stack gas flow rate, diluent gas, and moisture monitoring systems, your monitoring plan shall include the applicable information required for those systems under 40 CFR 75.53 (g) and (h) of this chapter.

7.1.1.2.1 Electronic. Your electronic monitoring plan records must include the following information: Unit or stack ID number(s); unit information (type of unit, maximum rated heat input, fuel type(s), emission controls); monitoring location(s); the monitoring methodologies used; monitoring system information, including (as applicable): Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; operating range and load information; monitor span and range information; units of measure of your PM concentrations (see section 3.2.2 of this appendix); and appropriate default values. Your electronic monitoring plan shall be evaluated and submitted using the ECMPS reporting tool provided by the EPA.

7.1.1.2.2 Hard Copy. You must keep records of the following items: Schematics and/or blueprints showing the location of the PM monitoring system(s) and test ports; data flow diagrams; test protocols; and miscellaneous technical justifications. The hard copy portion of the monitoring plan must also explain how the PM concentrations are measured and how they are converted to the units of the applicable emissions limit. The equation(s) used for the conversions must be documented. Electronic storage of the hard copy portion of the monitoring plan is permitted.

7.1.2 Operating Parameter Records. You must record the following information for each operating hour of each EGU and also for each group of EGUs utilizing a monitored common stack, to the extent that these data are needed to convert PM concentration data to the units of the emission standard. For non-operating hours, you must record only the items in sections 7.1.2.1 and 7.1.2.2 of this appendix. If you elect to or are required to comply with a gross output-based PM standard, for any hour in which there is gross output greater than zero, you must record the items in sections 7.1.2.1 through 7.1.2.3 and (if applicable) 7.1.2.5 of this appendix; however, if there is heat input to

the unit(s) but no gross output (*e.g.*, at unit startup), you must record the items in sections 7.1.2.1, 7.1.2.2, and, if applicable, section 7.1.2.5 of this appendix. If you elect to comply with a heat input-based PM standard, you must record only the items in sections 7.1.2.1, 7.1.2.2, 7.1.2.4, and, if applicable, section 7.1.2.5 of this appendix.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from 1 hundredth to 1 quarter of an hour, at your option);

7.1.2.3 The hourly gross output (rounded to nearest MWe);

7.1.2.4 If applicable, the F*c* factor or dry-basis F-factor used to calculate the heat input-based PM emission rate; and

7.1.2.5 If applicable, a flag to indicate that the hour is an exempt startup or shutdown hour.

7.1.3 PM Concentration Records. For each affected unit or common stack using a PM CEMS, you must record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes for the PM CEMS, as provided in the electronic monitoring plan, if your CEMS provides a quality-assured value of PM concentration for the hour;

7.1.3.3 The hourly PM concentration, in units of measure that correspond to your PM CEMS correlation curve, for each operating hour in which a quality-assured value is obtained. Record all PM concentrations with one leading non-zero digit and one decimal place, expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged.

7.1.3.4 A special code, indicating whether or not a quality-assured PM concentration is obtained for the hour; and

7.1.3.5 Monitor data availability for PM concentration, as a percentage of unit or stack operating hours calculated in the manner established for SO*2*, CO*2*, O*2* or moisture monitoring systems according to 40 CFR 75.32 of this chapter.

7.1.4 Stack Gas Volumetric Flow Rate Records.

7.1.4.1 When a gross output-based PM emissions limit must be met, in units of lb/MWh, you must obtain hourly measurements of stack gas volumetric flow rate during EGU operation, in order to convert PM concentrations to units of the standard.

7.1.4.2 When hourly measurements of stack gas flow rate are needed, you must keep hourly records of the flow rates and related information, as specified in 40 CFR 75.57(c)(2) of this chapter.

7.1.5 Records of Diluent Gas (CO*2* or O*2*) Concentration.

7.1.5.1 When a heat input-based PM emission limit must be met, in units of lb/MMBtu, you must obtain hourly measurements of CO*2* or O*2* concentration during EGU operation, in order to convert PM concentrations to units of the standard.

7.1.5.2 When hourly measurements of diluent gas concentration are needed, you must keep hourly CO*2* or O*2* concentration records, as specified in 40 CFR 75.57(g) of this chapter.

7.1.6 Records of Stack Gas Moisture Content.

7.1.6.1 When corrections for stack gas moisture content are needed to demonstrate compliance with the applicable PM emissions limit:

7.1.6.1.1 If you use a continuous moisture monitoring system, you must keep hourly records of the stack gas moisture content and related information, as specified in 40 CFR 75.57(c)(3) of this chapter.

7.1.6.1.2 If you use a fuel-specific default moisture value, you must represent it in the electronic monitoring plan required under section 7.1.1.2.1 of this appendix.

7.1.7 PM Emission Rate Records. For applicable PM emission limits in units of lb/MMBtu or lb/MWh, you must record the following information for each affected EGU or common stack:

7.1.7.1 The date and hour;

7.1.7.2 The hourly PM emissions rate (lb/MMBtu or lb/MWh, as applicable), calculated according to section 6.2.2 or 6.2.3 of this appendix, rounded to the same precision as the standard (*i.e.*, with one leading non-zero digit and one decimal place, expressed in scientific notation), expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged. You must calculate the PM emission rate only when valid values of PM concentration and all other required parameters required to convert PM concentration to the units of the standard are obtained for the hour;

7.1.7.3 An identification code for the formula used to derive the hourly PM emission rate from measurements of the PM concentration and other necessary parameters (*i.e.*, Equation C-3 or C-4 in section 6.2.3 of this appendix or the applicable EPA test Method 19 equation);

7.1.7.4 If applicable, indicate that the diluent cap has been used to calculate the PM emission rate; and

7.1.7.5 If applicable, indicate that the default electrical load (as defined in 40 CFR 63.10042) has been used to calculate the hourly PM emission rate.

7.1.7.6 Indicate that the PM emission rate was not calculated for the hour, if valid data are not obtained for PM concentration and/or any of the other parameters in the PM emission rate equation. For the purposes of this appendix, substitute data values for stack gas flow rate, CO_2 concentration, O_2 concentration, and moisture content reported under part 75 of this chapter are not considered to be valid data. However, when the gross output (as defined in 40 CFR 63.10042) is reported for an operating hour with zero output, the default electrical load value is treated as quality-assured data.

7.1.8 Other Parametric Data. If your PM CEMS measures PM concentrations at actual conditions, you must keep records of the temperatures and pressures used in Equation C-1 or C-2 to convert the measured hourly PM concentrations to standard conditions.

7.1.9 Certification, Recertification, and Quality Assurance Test Records. For any PM CEMS used to provide data under this subpart, you must record the following certification, recertification, and quality assurance information:

7.1.9.1 The test dates and times, reference values, monitor responses, monitor full scale value, and calculated results for the required 7-day drift tests and for the required daily zero and upscale calibration drift tests;

7.1.9.2 The test dates and times and results (pass or fail) of all daily system optics checks and daily sample volume checks of the PM CEMS (as applicable);

7.1.9.3 The test dates and times, reference values, monitor responses, and calculated results for all required quarterly ACAs;

7.1.9.4 The test dates and times, reference values, monitor responses, and calculated results for all required quarterly SVAs of extractive PM CEMS;

7.1.9.5 The test dates and times, reference method readings and corresponding PM CEMS responses (including the units of measure), and the calculated results for all PM CEMS correlation tests, RRAs and RCAs. For the correlation tests, you must indicate which model is used (*i.e.,* linear, logarithmic, exponential, polynomial, or power) and record the correlation equation. For the RRAs and RCAs, the reference method readings and PM CEMS responses must be reported in the same units of measure as the PM CEMS correlation;

7.1.9.6 The cycle time and sample delay time for PM CEMS that operate in batch sampling mode; and

7.1.9.7 Supporting information for all required PM CEMS correlation tests, RRAs, and RCAs, including records of all raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, as well as records of sampling equipment calibrations, reference monitor calibrations, and analytical equipment calibrations.

7.1.10 For stack gas flow rate, diluent gas, and moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in 40 CFR 75.59(a) of this chapter.

7.1.11 For each temperature measurement device (*e.g.,* resistance temperature detector or thermocouple) and pressure measurement device used to convert measured PM concentrations to standard conditions according to Equation C-1 or C-2, you must keep records of all calibrations and other checks performed to ensure that accurate data are obtained.

7.2 *Reporting Requirements.*

7.2.1 General Reporting Provisions. You must comply with the following requirements for reporting PM emissions from each affected EGU (or group of EGUs monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with section 7.2.2 of this appendix;

7.2.1.2 Monitoring plan reporting, in accordance with section 7.2.3 of this appendix;

7.2.1.3 Certification, recertification, and quality assurance test submittals, in accordance with section 7.2.4 of this appendix; and

7.2.1.4 Electronic quarterly emissions report submittals, in accordance with section 7.2.5 of this appendix.

7.2.2 Notifications. You must provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with 40 CFR 63.10030.

7.2.3 Monitoring Plan Reporting. For each affected unit (or group of units monitored at a common stack) under this subpart using PM CEMS to measure PM emissions, you must make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 For an EGU that begins reporting hourly PM concentrations on January 1, 2024, with a previously certified PM CEMS, submit the monitoring plan information in section 7.1.1.2 of this appendix prior to or concurrent with the first required quarterly emissions report. For a new EGU, or for an EGU switching to continuous monitoring of PM emissions after having implemented another allowable compliance option under this subpart, submit the information in section 7.1.1.2 of this appendix at least 21 days prior to the start of initial certification testing of the PM CEMS. Also submit the monitoring plan information in 40 CFR 75.53(g) pertaining to any required flow rate, diluent gas, and moisture monitoring systems within the applicable time frame specified in this section, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in section 7.1.1.1 of this appendix, you must submit the updated information either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS reporting tool. Hard copy portions of the monitoring plan shall be submitted to the appropriate delegated authority.

7.2.4 Certification, Recertification, and Quality-Assurance Test Reporting. Except for daily quality assurance tests of the required monitoring systems (*i.e.*, calibration error or drift tests, sample volume checks, system optics checks, and flow monitor interference checks), you must submit the results of all required certification, recertification, and quality-assurance tests described in sections 7.1.9.1 through 7.1.9.6 and 7.1.10 of this appendix electronically (except for test results previously submitted, *e.g.*, under the Acid Rain Program), using the ECMPS reporting tool. Submit the results of the quality assurance test (*i.e.*, RCA or RRA) or, if applicable, a new PM CEMS correlation test, either prior to or concurrent with the relevant quarterly electronic emissions report. If this is not possible, you have up to 60 days after the test completion date to submit the test results; in this case, you may claim provisional status for the emissions data affected by the quality assurance test or correlation, starting from the date and hour in which the test was completed and continuing until the date and hour in which the test results are submitted. For an RRA or RCA, if the applicable audit specifications are met, the status of the emissions data in the relevant time period changes from provisional to quality-assured, and no further action is required. For a successful correlation test, apply the correlation equation retrospectively to the raw data to change the provisional status of the data to quality-assured, and resubmit the affected emissions report(s). However, if the applicable performance specifications are not met, the provisional data must be invalidated, and resubmission of the affected quarterly emission report(s) is required. For a failed RRA or RCA, you must take corrective actions and proceed according to the applicable requirements found in sections 10.5 through 10.7 of Procedure 2 until a successful quality assurance test report is submitted. If a correlation test is unsuccessful, you may not report quality-assured data from the PM CEMS until the results of a subsequent correlation test show that the specifications in section 13.0 of PS 11 are met.

7.2.5 Quarterly Reports.

7.2.5.1 For each affected EGU (or group of EGUs monitored at a common stack), the owner or operator must use the ECMPS reporting tool to submit electronic quarterly emissions reports to the Administrator, in a format specified by the Administrator, starting with a report for the later of:

7.2.5.1.1 The first calendar quarter of 2024; or

7.2.5.1.2 The calendar quarter in which the initial PM CEMS correlation test is completed.

7.2.5.2 You must submit the electronic reports within 30 days following the end of each calendar quarter, except for EGUs that have been placed in long-term cold storage (as defined in section 72.2 of this chapter).

7.2.5.3 Each of your electronic quarterly reports shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in sections 7.1.2 through 7.1.7 of this appendix that is applicable to your PM emission measurement methodology; and

7.2.5.3.4 The results of all daily quality assurance assessments, *i.e.*, calibration drift checks and (if applicable) sample volume checks of the PM CEMS, calibration error tests of the other continuous monitoring systems that are used to convert PM concentration to units of the standard, and (if applicable) flow monitor interference checks.

7.2.5.4 Compliance Certification. Based on a reasonable inquiry of those persons with primary responsibility for ensuring that all PM emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator must submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[85 FR 55769, Sept. 9, 2020, as amended at 89 FR 38592, May 7, 2024; 91 FR 9132, Feb. 24, 2026]

Appendix D to Subpart UUUUU of Part 63—PM CPMS Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the continuous monitoring of the output from a PM CPMS, for the purpose of assessing continuous compliance with an applicable emissions limit in Table 1 or Table 2 to this subpart.

1.2 *Summary of the Method.* The output from an instrument capable of continuously measuring PM concentration is continuously recorded, either in milliamps, PM concentration, or other units of measure. An operating limit for the PM CPMS is established initially, based on data recorded by the monitoring system during a performance stack test. The performance test is repeated annually, and the operating limit is reassessed. In-between successive performance tests, the output from the PM CPMS serves as an indicator of continuous compliance with the applicable emissions limit.

2. Continuous Monitoring of the PM CPMS Output

2.1 *System Design and Performance Criteria.* The PM CPMS must meet the design and performance criteria specified in 40 CFR 63.10010(h)(1)(i) through (iii) and 40 CFR 63.10023(b)(2)(iii) and (iv). In addition, an automated DAHS is required to record the output from the PM CPMS and to generate the quarterly electronic data reports required under section 3.2.4 of this appendix.

2.2 *Installation Requirements.* Install the PM CPMS at an appropriate location in the stack or duct, in accordance with 40 CFR 63.10010(a).

2.3 *Determination of Operating Limits.*

2.3.1 In accordance with 40 CFR 63.10007(a)(3), 40 CFR 63.10011(b), 40 CFR 63.10023(a), and Table 6 to this subpart, you must determine an initial site-specific operating limit for your PM CPMS, using data recorded by the monitoring system during a performance stack test that demonstrates compliance with one of the following emissions limits in Table 1 or Table 2 to this subpart: Filterable PM; total non-Hg HAP metals; total HAP metals including Hg (liquid oil-fired units, only); individual non-Hg HAP metals; or individual HAP metals including Hg (liquid oil-fired units, only).

2.3.2 In accordance with 40 CFR 63.10005(d)(2)(i), you must perform the initial stack test no later than the applicable date in 40 CFR 63.9984(f), and according to 40 CFR 63.10005(d)(2)(iii) and 63.10006(a), the performance test must be repeated annually to document compliance with the emissions limit and to reassess the operating limit.

2.3.3 Calculate the operating limits according to 40 CFR 63.10023(b)(1) for existing units, and 40 CFR 63.10023(b)(2) for new units.

2.4 *Data Reduction and Compliance Assessment.*

2.4.1 Reduce the output from the PM CPMS to hourly averages, in accordance with 40 CFR 63.8(g)(2) and (5).

2.4.2 To determine continuous compliance with the operating limit, you must calculate 30-boiler operating day rolling average values of the output from the PM CPMS, in accordance with 40 CFR 63.10010(h)(3) through (6), 40 CFR 63.10021(c), and Table 7 to this subpart.

2.4.3 In accordance with 40 CFR 63.10005(d)(2)(ii), 40 CFR 63.10022(a)(2), and Table 4 to this subpart, the 30-boiler operating day rolling average PM CPMS output must be maintained at or below the operating limit. However, if exceedances of the operating limit should occur, you must follow the applicable procedures in 40 CFR 63.10021(c)(1) and (2).

3. RECORDKEEPING AND REPORTING.

3.1 *Recordkeeping Provisions.* You must keep the applicable records required under 40 CFR 63.10032(b) and (c) for your PM CPMS. In addition, you must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with 40 CFR 63.10033.

3.1.1 Monitoring Plan Records.

3.1.1.1 You must develop and maintain a site-specific monitoring plan for your PM CPMS, in accordance with 63.10000(d).

3.1.1.2 In addition to the site-specific monitoring plan required under § 63.10000(d), you must use the ECMPS reporting tool to prepare and maintain an electronic monitoring plan for your PM CPMS.

3.1.1.2.1 Contents of the Electronic Monitoring Plan. The electronic monitoring plan records must include the unit or stack ID number(s), monitoring location(s), the monitoring methodology used (*i.e.*, PM CPMS), the current operating limit of the PM CPMS (including the units of measure), unique system and component ID numbers, the make, model, and serial number of the PM CPMS, the analytical principle of the monitoring system, and monitor span and range information.

3.1.1.2.2 Electronic Monitoring Plan Updates. If you replace or make a change to a PM CPMS that is used to provide data under this subpart (including a change in the automated DAHS) and the replacement or change affects information reported in the electronic monitoring plan (*e.g.*, changes to the make, model and serial number when a PM CPMS is replaced), you must update the monitoring plan.

3.1.2 Operating Parameter Records. You must record the following information for each operating hour of each affected unit and for each group of units utilizing a common stack. For non-operating hours, record only the items in sections 3.1.2.1 and 3.1.2.2 of this appendix.

3.1.2.1 The date and hour;

3.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from 1 hundredth to 1 quarter of an hour, at the option of the owner or operator); and

3.1.2.3 If applicable, a flag to indicate that the hour is an exempt startup or shutdown hour.

3.1.3 PM CPMS Output Records. For each affected unit or common stack using a PM CPMS, you must record the following information for each unit or stack operating hour:

3.1.3.1 The date and hour;

3.1.3.2 Monitoring system and component identification codes for the PM CPMS, as provided in the electronic monitoring plan, for each operating hour in which the monitoring system is not out-of-control and a valid value of the output parameter is obtained;

3.1.3.3 The hourly average output from the PM CPMS, for each operating hour in which the monitoring system is not out-of-control and a valid value of the output parameter is obtained, either in milliamps, PM concentration, or other units of measure, as applicable;

3.1.3.4 A special code for each operating hour in which the PM CPMS is out-of-control and a valid value of the output parameter is not obtained; and

3.1.3.5 Percent monitor data availability for the PM CPMS, calculated in the manner established for SO*2*, CO*2*, O*2* or moisture monitoring systems according to section 75.32 of this chapter.

3.1.4 Records of PM CPMS Audits and Out-of-Control Periods. In accordance with 40 CFR 63.10010(h)(7), you must record, and make available upon request, the results of PM CPMS performance audits, as well as the dates of PM CPMS out-of-control periods and the corrective actions taken to return the system to normal operation.

3.2 *Reporting Requirements.*

3.2.1 General Reporting Provisions. You must comply with the following requirements for reporting PM CPMS data from each affected EGU (or group of EGUs monitored at a common stack) under this subpart:

3.2.1.1 Notifications, in accordance with section 3.2.2 of this appendix;

3.2.1.2 Monitoring plan reporting, in accordance with section 3.2.3 of this appendix;

3.2.1.3 Report submittals, in accordance with sections 3.2.4 and 3.2.5 of this appendix.

3.2.2 Notifications. You must provide notifications for the affected unit (or group of units monitored at a common stack) in accordance with 40 CFR 63.10030.

3.2.3 Monitoring Plan Reporting. For each affected unit (or group of units monitored at a common stack) under this subpart using a PM CPMS you must make monitoring plan submittals as follows:

3.2.3.1 For units using the PM CPMS compliance option prior to January 1, 2024, submit the electronic monitoring plan information in section 3.1.1.2.1 of this appendix prior to or concurrent with the first required electronic quarterly report. For units switching to the PM CPMS methodology on or after January 1, 2024, submit the electronic monitoring plan no later than 21 days prior to the date on which the PM test is performed to establish the initial operating limit.

3.2.3.2 Whenever an update of the electronic monitoring plan is required, as provided in section 3.1.1.2.2 of this appendix, the updated information must be submitted either prior to or concurrent with the relevant quarterly electronic emissions report.

3.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS reporting tool.

3.2.3.4 In accordance with 40 CFR 63.10000(d), you must submit the site-specific monitoring plan described in section 3.1.1.1 of this appendix to the Administrator, if requested.

3.2.4 Electronic Quarterly Reports.

3.2.4.1 For each affected EGU (or group of EGUs monitored at a common stack) that is subject to the provisions of this appendix, reporting of hourly responses from the PM CPMS will begin either with the first operating hour in the third quarter of 2023 or the first operating hour after completion of the initial stack test that establishes the operating limit, whichever is later. The owner or operator must then use the ECMPS reporting tool to submit electronic quarterly reports to the Administrator, in a format specified by the Administrator, starting with a report for the later of:

3.2.4.1.1 The first calendar quarter of 2024; or

3.2.4.1.2 The calendar quarter in which the initial operating limit for the PM CPMS is established.

3.2.4.2 The electronic quarterly reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage (as defined in section 72.2 of this chapter).

3.2.4.3 Each electronic quarterly report shall include the following information:

3.2.4.3.1 The date of report generation;

3.2.4.3.2 Facility identification information; and

3.2.4.3.3 The information in sections 3.1.2 and 3.1.3 of this appendix.

3.2.4.4 Compliance Certification. Based on a reasonable inquiry of those persons with primary responsibility for ensuring that the output from the PM CPMS has been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

3.2.5 Performance Stack Test Results. You must use the ECMPS reporting tool to report the results of all performance stack tests conducted to document compliance with the applicable emissions limit in table 1 or 2 to this subpart, as follows:

3.2.5.1 Report a summary of each test electronically, in a format specified by the Administrator, in the relevant quarterly compliance report under § 63.10031(g); and

3.2.5.2 Provide a complete stack test report as a PDF file, in accordance with 40 CFR 63.10031(f) or (h), as applicable.

[85 FR 55774, Sept. 9, 2020; 89 FR 38593, May 7, 2024; 91 FR 9132, Feb. 26, 2026]

Appendix E to Subpart UUUUU of Part 63—Data Elements

1.0 You must record the electronic data elements in this appendix that apply to your compliance strategy under this subpart. The applicable data elements in sections 2 through 13 of this appendix must be reported in the quarterly compliance reports required under § 63.10031(g), in a format specified by the Administrator, starting with a report that covers the first quarter of 2024. For stack tests used to demonstrate compliance, RATAs, PM CEMS correlations, RRAs and RCAs that are completed on and after January 1, 2024, the applicable data elements in sections 17 through 30 of this appendix must be reported in an XML format prescribed by the Administrator, and the information in section 31 of this appendix must be reported in as one or more PDF files.

2.0 *MATS Compliance Report Root Data Elements.* You must record the following data elements and include them in each quarterly compliance report:

2.1 Energy Information Administration's Office of Regulatory Information Systems (ORIS) Code;

2.2 Facility Name;

2.3 Facility Registry Identifier;

2.4 Title 40 Part;

2.5 Applicable Subpart;

2.6 Calendar Year;

2.7 Calendar Quarter; and

2.8 Submission Comment (optional)

3.0 *Performance Stack Test Summary.* If you elect to demonstrate compliance using periodic performance stack testing (including 30-boiler operating day Hg LEE tests), record the following data elements for each test:

3.1 Parameter

3.2 Test Location ID;

3.3 Test Number;

3.4 Test Begin Date, Hour, and Minute;

3.5 Test End Date, Hour, and Minute;

3.6 Timing of Test (either performed on-schedule according to 40 CFR 63.10006(f), or was late);

3.7 Averaging Plan Indicator;

3.8 Averaging Group ID (if applicable);

3.9 EPA Test Method Code;

3.10 Emission Limit, Including Units of Measure;

3.11 Average Pollutant Emission Rate;

3.12 LEE Indicator;

3.13 LEE Basis (if applicable); and

3.14 Submission Comment (optional)

4.0 *Operating limit Data (PM CPMS, only):*

4.1 Parameter Type;

4.2 Operating Limit; and

4.3 Units of Measure.

5.0 *Performance Test Run Data.* For each run of the performance stack test, record the following data elements:

5.1 Run Number

5.2 Run Begin Date, Hour, and Minute;

5.3 Run End Date, Hour, and Minute;

5.4 Pollutant Concentration and Units of Measure;

5.5 Emission Rate;

5.6 EPA Test Method 19 Equation (if applicable);

5.7 Total Sampling Time; and

5.8 Total Sample Volume.

6.0 *Conversion Parameters.* For the parameters that are used to convert the pollutant concentration to units of the emission standard (including, as applicable, CO*2* or O*2* concentration, stack gas flow rate, stack gas moisture content, F-factors, and gross output), record:

6.1 Parameter Type;

6.2 Parameter Source; and

6.3 Parameter Value, Including Units of Measure.

7.0 *Quality Assurance Parameters:* For key parameters that are used to quality-assure the reference method data (including, as applicable, filter temperature, percent isokinetic, leak check results, percent breakthrough, percent spike recovery, and relative deviation), record:

7.1 Parameter Type;

7.2 Parameter Value; and

7.3 Pass/Fail Status.

8.0 *Averaging Group Configuration.* If a particular EGU or common stack is included in an averaging plan, record the following data elements:

8.1 Parameter Being Averaged;

8.2 Averaging Group ID; and

8.3 Unit or Common Stack ID.

9.0 *Compliance Averages.* If you elect to (or are required to) demonstrate compliance using continuous monitoring system(s) on a 30-boiler operating day rolling average basis (or on a 30- or 90-group boiler operating day rolling WAER basis, if your monitored EGU or common stack is in an averaging plan), you must record the following data elements for each average emission rate (or, for units in an averaging plan, for each WAER):

9.1 Unit or Common Stack ID;

9.2 Averaging Group ID (if applicable);

9.3 Parameter Being Averaged;

9.4 Date;

9.5 Average Type;

9.6 Units of Measure; and

9.7 Average Value.

9.8 Comment Field.

10.0 *Unit Information.* You must record the following data elements for each EGU:

10.1 Unit ID;

10.2 Date of Last Tune-up; and

10.3 Emergency Bypass Information. If your coal-fired EGU, solid oil-derived fuel-fired EGU, or IGCC is equipped with a main stack and a bypass stack (or bypass duct) configuration, and has qualified to use the LEE compliance option, you must report the following emergency bypass information annually, in the compliance report for the fourth calendar quarter of the year:

10.3.1 The number of emergency bypass hours for the year, as a percentage of the EGU's annual operating hours;

10.3.2 A description of each emergency bypass event during the year, including the cause and corrective actions taken;

10.3.3 An explanation of how clean fuels were burned to the maximum extent possible during each emergency bypass event;

10.3.4 An estimate of the emissions released during each emergency bypass event. You must also show whether LEE status has been retained or lost, based on the emissions estimate and the results of the previous LEE retest; and

10.3.5 If there were no emergency bypass events during the year, a statement to that effect.

11.0 *Fuel Usage Information.* If subject to an emissions limit, record the following monthly fuel usage information:

11.1 Calendar Month;

11.2 Each Type of Fuel Used During the Calendar Month in the Quarter;

11.3 Quantity of Each Type of Fuel Combusted in Each Calendar Month in the Quarter, with Units of Measure;

11.4 New Fuel Type Indicator (if applicable); and

11.5 Date of Performance Test Using the New Fuel (if applicable.

12.0 *Malfunction Information (if applicable):* If there was a malfunction of the process equipment or control equipment during the reporting period that caused (or may have caused) an exceedance of an emissions or operating limit, record:

12.1 Event Begin Date and Hour (if known);

12.2 Event End Date and Hour;

12.3 Malfunction Description; and

12.4 Corrective Action.

13.0 *Deviations and Monitoring Downtime.* If there were any deviations or monitoring downtime during the reporting period, record:

13.1 Unit, Common Stack, or Averaging Group ID;

13.2 The nature of the deviation, as either:

13.2.1 Emission limit exceeded;

13.2.2 Operating limit exceeded;

13.2.3 Work practice standard not met;

13.2.4 Testing requirement not met;

13.2.5 Monitoring requirement not met;

13.2.6 Monitoring downtime incurred; or

13.2.7 Other requirement not met.

13.3 A description of the deviation, or monitoring downtime, as follows:

13.3.1 For a performance stack test or a 30- (or 90-) boiler operating day rolling average that exceeds an emissions or operating limit, record the parameter (*e.g.*, HCl, Hg, PM), the limit that was exceeded, and either the date of the non-complying performance test or the beginning and ending dates of the non-complying rolling average;

13.3.2 If an unmonitored bypass stack was used during the reporting period, record the total number of hours of bypass stack usage;

13.3.3 For periods where valid monitoring data are not reported during the reporting period, record the monitored parameter, the total source operating time (hours), and the total number of hours of monitoring deviation or downtime and other information, as indicated, for:

13.3.3.1 Monitoring system malfunctions/repairs (deviation and downtime);

13.3.3.2 Out-of-control periods/repairs (deviation and downtime);

13.3.3.3 Non-monitoring equipment malfunctions (downtime);

13.3.3.4 QA/QC activities (excluding zero and span checks) (downtime);

13.3.3.5 Routine maintenance (downtime);

13.3.3.6 Other known causes (downtime); and

13.3.3.7 Unknown causes (downtime).

13.3.4 If a performance stack test was due within the quarter but was not done, record the parameter (*e.g.*, HCl, PM), the test deadline, and a statement that the test was not done as required;

13.3.5 For a late performance stack test conducted during the quarter, record the parameter, the test deadline, and the number of days that elapsed between the test deadline and the test completion date.

13.4 Record any corrective actions taken in response to the deviation.

13.5 If there were no deviations and/or no monitoring downtime during the quarter, record a statement to that effect.

14.0 *Reference Method Data Elements.* For each of the following tests that is completed on and after January 1, 2024, you must record and report the applicable electronic data elements in sections 17 through 29 of this appendix, pertaining to the reference method(s) used for the test (see section 16 of this appendix).

14.1 Each quarterly, annual, or triennial stack test used to demonstrate compliance (including 30- (or 90-) boiler operating day Hg LEE tests and PM tests used to set operating limits for PM CPMS);

14.2 Each RATA of your Hg, HCl, HF, or SO*2* CEMS or each RATA of your Hg sorbent trap monitoring system; and

14.3 Each correlation test, RRA and each RCA of your PM CEMS.

15.0 You must report the applicable data elements for each test described in section 14 of this appendix in an XML format prescribed by the Administrator.

15.1 For each stack test completed during a particular calendar quarter and contained in the quarterly compliance report, you must submit along with the quarterly compliance report, the data elements in sections 17 and 18 of this appendix (which are common to all tests) and the applicable data elements in sections 19 through 31 of this appendix associated with the reference method(s) used.

15.2 For each RATA, PM CEMS correlation, RRA, or RCA, when you use the ECMPS reporting tool to report the test results as required under appendix A, B, or C to this subpart or, for SO*2* RATAs under part 75 of this chapter, you must submit along with the test results, the data elements in sections 17 and 18 of this appendix and, for each test run, the data elements in sections 19 through 30 of this appendix that are associated with the reference method(s) used.

15.3 For each stack test, RATA, PM CEMS correlation, RRA, and RCA, you must also provide the information described in section 31 of this appendix as a PDF file, either along with the quarterly compliance report (for stack tests) or together with the test results reported under appendix A, B, or C to this subpart or part 75 of this chapter (for RATAs, RRAs, RCAs, or PM CEMS correlations).

16.0 *Applicable Reference Methods.* One or more of the following EPA reference methods is needed for the tests described in sections 14.1 through 14.3 of this appendix: Method 1, 2, 3A, 4, 5, 5D, 5I, 6C, 26, 26A, 29, and/or 30B.

16.1 Application of EPA test Methods 1 and 2. If you use periodic stack testing to comply with an *output-based* emissions limit, you must determine the stack gas flow rate during each performance test run in which EPA test Method 5, 5D, 5I, 26, 26A, 29, or 30B is used, in order to convert the measured pollutant concentration to units of the standard. For EPA test Methods 5, 5D, 5I, 26A and 29, which require isokinetic sampling, the delta-P readings made with the pitot tube and manometer at the EPA test Method 1 traverse points, taken together with measurements of stack gas temperature, pressure, diluent gas concentration (from a separate EPA test Method 3A or 3B test) and moisture, provide the necessary data for the EPA test Method 2 flow rate calculations. Note that even if you elect to comply with a *heat input-based* standard, when EPA test Method 5, 5D, 5I, 26A, or 29 is used, you must still use EPA test Method 2 to determine the average stack gas velocity (vs), which is needed for the percent isokinetic calculation. The EPA test Methods 26 and 30B do not require isokinetic sampling; therefore, when either of these methods is used, if the stack gas flow rate is needed to comply with the applicable *output-based* emissions limit, you must make a separate EPA test Method 2 determination during each test run.

16.2 Application of EPA test Method 3A. If you elect to perform periodic stack testing to comply with a *heat input-based* emissions limit, a separate measurement of the diluent gas (CO*2* or O*2*) concentration is required for each test run in which EPA test Method 5, 5D, 5I, 26, 26A, 29, or 30B is used, in order to convert the measured pollutant concentration to units of the standard. The EPA test Method 3A is the preferred CO*2* or O*2* test method, although EPA test Method 3B may be used instead. Diluent gas measurements are also needed for stack gas molecular weight determinations when using EPA test Method 2.

16.3 Application of EPA test Method 4. For performance stack tests, depending on which equation is used to convert pollutant concentration to units of the standard, measurement of the stack gas moisture content, using EPA test Method 4, may also be required for each test run. The EPA test Method 4 moisture data are also needed for the EPA test Method 2 calculations (to determine the molecular weight of the gas) and for the RATA of an Hg CEMS that measures on a wet basis, when EPA test Method 30B is used. Other applications that require EPA test Method 4 moisture determinations include: RATAs of an SO*2* monitor, when the reference method and CEMS data are measured on a different moisture basis (wet or dry); conversion of wet-basis pollutant concentrations to the units of a *heat input-based* emissions limit when certain EPA test Method 19 equations are used (*e.g.*, Eq. 19-3, 19-4, or 19-8); and stack gas molecular weight determinations. When EPA test Method 5, 5D, 5I, 26A, or 29 is used for the performance test, the EPA test Method 4 moisture determination may be made by using the water collected in the impingers together with data from the dry gas meter; alternatively, a separate EPA test Method 4 determination may be made. However, when EPA test Method 26 or 30B is used, EPA test Method 4 must be performed separately.

16.4 Applications of EPA test Methods 5, 5D, and 5I. The EPA test Method 5 (or, if applicable, 5D or 5I) must be used for the following applications: To demonstrate compliance with a filterable PM emissions limit; for PM tests used to set operating limits for PM CPMS; and for the initial correlations, RRAs and RCAs of a PM CEMS.

16.5 Applications of EPA test Method 6C. If you elect to monitor SO*2* emissions from your coal-fired EGU as a surrogate for HCl, the SO*2* CEMS must be installed, certified, operated, and maintained according to 40 CFR part 75. Part 75 allows the use of EPA test Methods 6, 6A, 6B, and 6C for the required RATAs of the SO*2* monitor. However, in practice, only instrumental EPA test Method 6C is used.

16.6 Applications of EPA test Methods 26 and 26A. The EPA test Method 26A may be used for quarterly HCl or HF stack testing, or for the RATA of an HCl or HF CEMS. The EPA test Method 26 may be used for quarterly HCl or HF stack testing; however, for the RATAs of an HCl monitor that is following PS 18 and Procedure 6 in appendices B and F to part 60 of this chapter, EPA test Method 26 may only be used if approved upon request.

16.7 Applications of EPA test Method 29. The EPA test Method 29 may be used for periodic performance stack tests to determine compliance with individual or total HAP metals emissions limits. For coal-fired EGUs, the total HAP emissions limits exclude Hg.

16.8 Applications of EPA test Method 30B. The EPA test Method 30B is used for 30- (or 90-) boiler operating day Hg LEE tests and RATAs of Hg CEMS and sorbent trap monitoring systems, and it may be used for quarterly Hg stack testing (oil-fired EGUs, only).

17.0 *Facility and Test Company Information.* In accordance with § 63.7(e)(3), a test is defined as three or more runs of one or more EPA Reference Method(s) conducted to measure the amount of a specific regulated pollutant, pollutants, or surrogates being emitted from a particular EGU (or group of EGUs that share a common stack), and to satisfy requirements of this subpart. On or after January 1, 2024, you must report the data elements in sections 17 and 18, each time that you complete a required performance stack test, RATA, PM CEMS correlation, RRA, or RCA at the affected EGU(s), using EPA test Method 5, 5B, 5D, 5I, 6C, 26, 26A, 29, or 30B. You must also report the applicable data elements in sections 19 through 25 of this appendix for each test. If any separate, corresponding EPA test Method 2, 3A, or 4 test is conducted in order to convert a pollutant concentration to the units of the applicable emission standard given in table 1 or table 2 of this subpart or to convert pollutant concentration from wet to dry basis (or vice-versa), you must also report the applicable data elements in sections 26 through 31 of this appendix.

The applicable data elements in sections 17 through 31 of this appendix must be submitted separately, in XML format, along with the quarterly Compliance Report (for stack tests) or along with the electronic test results submitted to the ECMPS reporting tool (for CMS performance evaluations). The Electronic Reporting Tool (ERT) or an equivalent schema can be utilized to create this XML file. Note: Ideally, for all of the tests completed at a given facility in a particular calendar quarter, the applicable data elements in sections 17 through 31 of this appendix should be submitted together in one XML file. However, as shown in table 8 to this subpart, the timelines for submitting stack test results and CMS performance evaluations are not identical. Therefore, for calendar quarters in which both types of tests are completed, it may not be possible to submit the applicable data elements for all of those tests in a single XML file; separate submittals may be necessary to meet the applicable reporting deadlines.

17.1 Part;

17.2 Subpart;

17.3 ORIS Code;

17.4 Facility Name;

17.5 Facility Address;

17.6 Facility City;

17.7 Facility County;

17.8 Facility State;

17.9 Facility Zip Code;

17.10 Facility Point of Contact;

17.11 Facility Contact Phone Number;

17.12 Facility Contact Email;

17.13 EPA Facility Registration System Number;

17.14 Source Classification Code;

17.15 State Facility ID;

17.16 Project Number;

17.17 Name of Test Company;

17.18 Test Company Address;

17.19 Test Company City;

17.20 Test Company State;

17.21 Test Company Zip Code;

17.22 Test Company Point of Contact;

17.23 Test Company Contact Phone Number;

17.24 Test Company Contact Email; and

17.25 Test Comment (optional, PM CPMS operating limits, if applicable).

18.0 *Source Information Data Elements.* You must report the following data elements, as applicable, for each source for which at least one test is included in the XML file:

18.1 Source ID (sampling location);

18.2 Stack (duct) Diameter (circular stack) (in.);

18.3 Equivalent Diameter (rectangular duct or stack) (in.);

18.4 Area of Stack;

18.5 Control Device Code; and

18.6 Control Device Description.

19.0 *Run-Level and Lab Data Elements for EPA test Methods 5, 5B, 5D, 5I, 26A, and 29.* You must report the appropriate Source ID (*i.e.,* Data Element 18.1) and the following data elements, as applicable, for each run of each performance stack test, PM CEMS correlation test, RATA, RRA, or RCA conducted using isokinetic EPA test Method 5, 5B, 5D, 5I, or 26A. If your EGU is oil-fired and you use EPA test Method 26A to conduct stack tests for both HCl and HF, you must report these data elements separately for each pollutant. When you use EPA test Method 29 to measure the individual HAP metals, total filterable HAP metals and total HAP metals, report only the run-level data elements (sections 19.1, 19.3 through 19.30, and 19.38 through 19.41 of this appendix), and the point-level and lab data elements in sections 20 and 21 of this appendix:

19.1 Test Number;

19.2 Pollutant Name;

19.3 EPA Test Method;

19.4 Run Number;

19.5 Corresponding Reference Method(s), if applicable;

19.6 Corresponding Reference Method(s) Run Number, if applicable;

19.7 Number of Traverse Points;

19.8 Run Begin Date;

19.9 Run Start Time (clock time start);

19.10 Run End Date;

19.11 Run End Time (clock time end);

19.12 Barometric Pressure;

19.13 Static Pressure;

19.14 Cumulative Elapsed Sampling Time;

19.15 Percent O_2;

19.16 Percent CO_2;

19.17 Pitot Tube ID;

19.18 Pitot Tube Calibration Coefficient;

19.19 Nozzle Calibration Diameter;

19.20 F-Factor (F_d, F_w, or F_c);

19.21 Calibration Coefficient of Dry Gas Meter (Y);

19.22 Total Volume of Liquid Collected in Impingers and Silica Gel;

19.23 Percent Moisture—Actual;

19.24 Dry Molecular Weight of Stack Gas;

19.25 Wet Molecular Weight of Stack Gas;

19.26 Initial Reading of Dry Gas Meter Volume (dcf);

19.27 Final Reading of Dry Gas Meter Volume (dcf);

19.28 Stack Gas Velocity—fps;

19.29 Stack Gas Flow Rate—dscfm;

19.30 Type of Fuel;

19.31 Pollutant Mass Collected (value);

19.32 Pollutant Mass Unit of Measure;

19.33 Detection Limit Flag;

19.34 Pollutant Concentration;

19.35 Pollutant Concentration Unit of Measure;

19.36 Pollutant Emission Rate;

19.37 Pollutant Emission Rate Units of Measure (in units of the standard);

19.38 Compliance Limit Basis (heat input or electrical output);

19.39 Heat Input or Electrical Output Unit of Measure;

19.40 Process Parameter (value);

19.41 Process Parameter Unit of Measure;

19.42 Converted Concentration for PM CEMS only; and

19.43 Converted Concentration Units (units of correlation for PM CEMS).

20.0 *Point-Level Data Elements for EPA test Methods 5, 5B, 5D, 5I, 26A, & 29.* To link the point-level data with the run data in the xml schema, you must report the Source ID (*i.e.*, Data Element 18.1), EPA Test Method (Data Element 19.3), Run Number (Data Element 19.4), and Run Begin Date (Data Element 19.8) with the following point-level data elements for each run of each performance stack test, PM CEMS correlation test, RATA, RRA, or RCA conducted using isokinetic EPA test Method 5, 5B, 5D, 5I, 26A, or 29. Note that these data elements are required for all EPA test Method 29 applications, whether the method is being used to measure the total or individual HAP metals concentrations:

20.1 Traverse Point ID;

20.2 Stack Temperature;

20.3 Differential Pressure Reading (ΔP);

20.4 Orifice Pressure Reading (ΔH);

20.5 Dry Gas Meter Inlet Temperature;

20.6 Dry Gas Meter Outlet Temperature; and

20.7 Filter Temperature.

21.0 *Laboratory Results for EPA test Methods 29 Total or Individual Multiple HAP Metals.* If you use EPA test Method 29 and elect to comply with the total or individual HAP metals standards, you must report run-level data elements 19.1 through 19.34 in Section 19, and the point-level data elements in Section 20. To link the laboratory data with the run data in the xml schema, you must report the Source ID (*i.e.*, Data Element 18.1), EPA Test Method (Data Element 19.3), Run Number (Data Element 19.4), and Run Begin Date (Data Element 19.8) with the results of the laboratory analyses. Regardless of whether you elect to comply with the total HAP metals standard or the individual HAP metals standard, you must report the front half catch, the back half catch, and the sum of the front and back half catches collected with EPA test Method 29 for each individual HAP metal and for the total HAP metals. The list of individual HAP metals is Antimony, Arsenic, Beryllium, Cadmium, Chromium, Cobalt, Lead, Manganese, Nickel, Selenium, and Mercury (if applicable). You must also calculate and report the pollutant emission rates(s) in relation to the standard(s) with which you have elected to comply and the units specified in Table 5 as follows:

21.1 Each Individual HAP metal total mass collected:

21.1.1 Pollutant Name;

21.1.2 Pollutant Mass Collected;

21.1.3 Pollutant Mass Units of Measure; and

21.1.4 Detection Limit Flag.

21.2 Each Individual HAP metal Front Half:

21.2.1 Pollutant Name;

21.2.2 Pollutant Mass Collected;

21.2.3 Pollutant Mass Units of Measure; and

21.2.4 Detection Limit Flag.

21.3 Each Individual HAP metal Back Half:

21.3.1 Pollutant Name;

21.3.2 Pollutant Mass Collected;

21.3.3 Pollutant Mass Units of Measure; and

21.3.4 Detection Limit Flag.

21.4 Each Individual HAP metal concentration:

21.4.1 Pollutant Name;

21.4.2 Pollutant Concentration; and

21.4.3 Pollutant Concentration Units of Measure.

21.5 Each Individual HAP metal emission rate in units of the standard:

21.5.1 Pollutant Name;

21.5.2 Pollutant Emission Rate; and

21.5.3 Pollutant Emission Rate Units of Measure.

21.6 Each Individual HAP metal emission rate in units of lbs/MMBTU or lbs/MW (per Table 5):

21.6.1 Pollutant Name;

21.6.2 Pollutant Emission Rate; and

21.6.3 Pollutant Emission Rate Units of Measure.

21.7 Total Filterable HAP metals mass collected:

21.7.1 Pollutant Name;

21.7.2 Pollutant Mass Collected;

21.7.3 Pollutant Mass Units of Measure; and

21.7.4 Detection Limit Flag.

21.8 Total Filterable HAP metals concentration:

21.8.1 Pollutant Name;

21.8.2 Pollutant Concentration; and

21.8.3 Pollutant Concentration Units of Measure.

21.9 Total Filterable HAP metals in units of lbs/MMBtu or lbs/MW (per Table 5):

21.9.1 Pollutant Name;

21.9.2 Pollutant Emission Rate; and

21.9.3 Pollutant Emission Rate Units of Measure.

21.10 Total HAP metals mass collected:

21.10.1 Pollutant Name;

21.10.2 Pollutant Mass Collected;

21.10.3 Pollutant Mass Units of Measure; and

21.10.4 Detection Limit Flag.

21.11 Total HAP metals concentration

21.11.1 Pollutant Name;

21.11.2 Pollutant Concentration; and

21.11.3 Pollutant Concentration Units of Measure.

21.12 Total HAP metals Emission Rate in Units of the Standard:

21.12.1 Pollutant Name;

21.12.2 Pollutant Emission Rate; and

21.12.3 Pollutant Emission Rate Units of Measure.

21.13 Total HAP metals Emission Rate in lbs/MMBtu or lbs/MW (per Table 5):

21.13.1 Pollutant Name;

21.13.2 Pollutant Emission Rate; and

21.13.3 Pollutant Emission Rate Units of Measure.

22.0 *Run-Level and Lab Data Elements for EPA test Method 26.* If you use EPA test Method 26, you must report the Source ID (*i.e.*, Data Element 18.1) and the following run-level data elements for each test run. If your EGU is oil-fired and you use EPA test Method 26 to conduct stack tests for both HCl and HF, you must report these data elements separately for each pollutant:

22.1 Test Number;

22.2 Pollutant Name;

22.3 EPA Test Method;

22.4 Run Number;

22.5 Corresponding Reference Method(s), if applicable;

22.6 Corresponding Reference Method(s) Run Number, if applicable;

22.7 Number of Traverse Points;

22.8 Run Begin Date;

22.9 Run Start Time (clock start time);

22.10 Run End Date;

22.11 Run End Time (clock end time);

22.12 Barometric Pressure;

22.13 Cumulative Elapsed Sampling Time;

22.14 Calibration Coefficient of Dry Gas Meter (Y);

22.15 Initial Reading of Dry Gas Meter Volume (dcf);

22.16 Final Reading of Dry Gas Meter Volume (dcf);

22.17 Percent O*2*;

22.18 Percent CO*2*;

22.19 Type of Fuel;

22.20 F-Factor (F*d*, F*w*, or F*c*);

22.21 Pollutant Mass Collected (value);

22.22 Pollutant Mass Units of Measure;

22.23 Detection Limit Flag;

22.24 Pollutant Concentration;

22.25 Pollutant Concentration Unit of Measure;

22.26 Compliance Limit Basis (heat input or electrical output);

22.27 Heat Input or Electrical Output Unit of Measure;

22.28 Process Parameter (value);

22.29 Process Parameter Unit of Measure;

22.30 Pollutant Emission Rate; and

22.31 Pollutant Emission Rate Units of Measure (in the units of the standard).

23.0 *Point-Level Data Elements for EPA test Method 26.* To link the point-level data in this section with the run-level data in the XML schema, you must report the Source ID (*i.e.*, Data Element 18.1), EPA Test Method (Data Element 22.3), Run Number (Data Element 22.4), and Run Begin Date (Data Element 22.8) from section 22 and the following point-level data elements for each run of each EPA test Method 26 test:

23.1 Traverse Point ID;

23.2 Filter Temperature; and

23.3 Dry Gas Meter Temperature.

24.0 *Run-Level Data for EPA test Method 30B.* You must report Source ID (*i.e.* Data Element 18.1) and the following run-level data elements for each EPA test Method 30B test run:

24.1 Test Number;

24.2 Pollutant Name;

24.3 EPA Test Method;

24.4 Run Number;

24.5 Corresponding Reference Method(s), if applicable;

24.6 Corresponding Reference Method(s) Run Number, if applicable;

24.7 Number of Traverse Points;

24.8 Run Begin Date;

24.9 Run Start Time (clock time start);

24.10 Run End Date;

24.11 Run End Time (clock time end);

24.12 Barometric Pressure;

24.13 Percent O*2*;

24.14 Percent CO*2*;

24.15 Cumulative Elapsed Sampling Time;

24.16 Calibration Coefficient of Dry Gas Meter Box A (Y);

24.17 Initial Reading of Dry Gas Meter Volume (A);

24.18 Final Reading of Dry Gas Meter Volume (A);

24.19 Calibration Coefficient of Dry Gas Meter Box B (Y);

24.20 Initial Reading of Dry Gas Meter Volume (B);

24.21 Final Reading of Dry Gas Meter Volume (B);

24.22 Gas Sample Volume Units of Measure;

24.23 Post-Run Leak Rate (A);

24.24 Post-Run Leak Check Vacuum (A);

24.25 Post-Run Leak Rate (B);

24.26 Post-Run Leak Check Vacuum (B);

24.27 Sorbent Trap ID (A);

24.28 Pollutant Mass Collected, Section 1 (A);

24.29 Pollutant Mass Collected, Section 2 (A);

24.30 Mass of Spike on Sorbent Trap A;

24.31 Total Pollutant Mass Trap A;

24.32 Sorbent Trap ID (B);

24.33 Pollutant Mass Collected, Section 1 (B);

24.34 Pollutant Mass Collected, Section 2 (B);

24.35 Mass of Spike on Sorbent Trap B;

24.36 Total Pollutant Mass Trap B;

24.37 Pollutant Mass Units of Measure;

24.38 Pollutant Average Concentration;

24.39 Pollutant Concentration Units of Measure;

24.40 Method Detection Limit;

24.41 Percent Spike Recovery;

24.42 Type of Fuel;

24.43 F-Factor (F*d*, F*w*, or F*c*);

24.44 Compliance Limit Basis (heat input or electrical output);

24.45 Heat Input or Electrical Output Unit of Measure;

24.46 Process Parameter (value);

24.47 Process Parameter Unit of Measure;

24.48 Pollutant Emission Rate; and

24.49 Pollutant Emission Rate Unit of Measure (in the units of the standard).

25.0 *Point-Level Data Elements for EPA test Method 30B.* You must report the Source ID (*i.e.*, Data Element 18.1), EPA Test Method (Data Element 24.3), Run Number (Data Element 24.4), and Run Begin Date (Data Element 24.8) and the following point-level data elements for each run of each EPA test Method 30B test:

25.1 Traverse Point ID;

25.2 Dry Gas Meter Temperature (A);

25.3 Sample Flow Rate (A) (L/min);

25.4 Dry Gas Meter Temperature (B); and

25.5 Sample Flow Rate (B) (L/min).

26.0 *Pre-Run Data Elements for EPA test Methods 3A and 6C.* You must report the Source ID (*i.e.*, Data Element 18.1) and the following pre-run data elements for each SO_2 RATA using instrumental EPA test Method 6C, and for each instrumental EPA test Method 3A O_2 or CO_2 test that is performed to convert a pollutant concentration to the units of measure of the applicable emission unit of standard in Table 1 or 2 of this subpart:

26.1 Test Number;

26.2 EPA Test Method;

26.3 Calibration Gas Cylinder Analyte;

26.4 Cylinder Gas Units of Measure;

26.5 Date of Calibration;

26.6 Calibration Low-Level Gas Cylinder ID;

26.7 Calibration Low-Level Gas Concentration;

26.8 Calibration Low-Level Cylinder Expiration Date;

26.9 Calibration Mid-Level Gas Cylinder ID;

26.10 Calibration Mid-Level Gas Concentration;

26.11 Calibration Mid-Level Cylinder Expiration Date;

26.12 Calibration High-Level Gas Cylinder ID;

26.13 Calibration Span (High-Level) Gas Concentration;

26.14 Calibration High-Level Cylinder Expiration Date;

26.15 Low-Level Gas Response;

26.16 Low-Level Calibration Error;

26.17 Low-Level Alternate Performance Specification (APS) Flag;

26.18 Mid-Level Gas Response;

26.19 Mid-Level Calibration Error;

26.20 Mid-Level APS Flag;

26.21 High-Level Gas Response;

26.22 High-Level Calibration Error; and

26.23 High-Level APS Flag.

27.0 *Run-Level Data Elements for EPA test Methods 3A and 6C.* You must report the Source ID (*i.e.*, Data Element 18.1) and following run-level data elements for each run of each SO*2* RATA using instrumental EPA test Method 6C, and for each run of each corresponding instrumental EPA test Method 3A test that is performed to convert a pollutant concentration to the applicable emission unit of standard in Table 1 or 2 of this subpart:

27.1 Test Number;

27.2 Pollutant or Analyte Name;

27.3 EPA Test Method;

27.4 Run Number;

27.5 Corresponding Reference Method(s), if applicable;

27.6 Corresponding Reference Method(s) Run Number(s), if applicable;

27.7 Number of Traverse Points;

27.8 Run Begin Date;

27.9 Run Start Time (clock time start);

27.10 Run End Date;

27.11 Run End Time (clock time end);

27.12 Cumulative Elapsed Sampling Time;

27.13 Upscale (mid or high) Gas Level;

27.14 Pre-Run Low-Level Response;

27.15 Pre-Run Low-Level System Bias;

27.16 Pre-Run Low-Level Bias APS Flag;

27.17 Pre-Run Upscale (mid or high) Response;

27.18 Pre-Run Upscale (mid or high) System Bias;

27.19 Pre-Run Upscale (mid or high) Bias APS Flag;

27.20 Post-Run Low-Level Response;

27.21 Post-Run Low-Level System Bias;

27.22 Post-Run Low-Level Bias APS Flag;

27.23 Post-Run Low-Level Drift;

27.24 Post-Run Low-Level Drift APS Flag;

27.25 Post-Run Upscale (mid or high) Response;

27.26 Post-Run Upscale (mid or high) System Bias;

27.27 Post-Run Upscale (mid or high) System Bias APS Flag;

27.28 Post-Run Upscale (mid or high) Drift;

27.29 Post-Run Upscale (mid or high) Drift APS Flag;

27.30 Unadjusted Raw Emissions Average Concentration;

27.31 Calculated Average Concentration, Adjusted for Bias (C*gas*);

27.32 Concentration Units of Measure (Dry or wet);

27.33 Type of Fuel;

27.34 Process Parameter (value); and

27.35 Process Parameter Units of Measure.

28.0 *Run-Level Data Elements for EPA test Method 2.* When you make a separate determination of the stack gas flow rate using EPA test Method 2 separately, corresponding to a pollutant reference method test, *i.e.,* when data from the pollutant reference method cannot determine the stack gas flow rate, you must report the Source ID (*i.e.,* Data Element 18.1) and following run-level data elements for each EPA test Method 2 test run:

28.1 Test Number;

28.2 EPA Test Method;

28.3 Run Number;

28.4 Number of Traverse Points;

28.5 Run Begin Date;

28.6 Run Start Time (clock time start);

28.7 Run End Date;

28.8 Run End Time (clock time end);

28.9 Pitot Tube ID;

28.10 Pitot Tube Calibration Coefficient;

28.11 Barometric Pressure;

28.12 Static Pressure;

28.13 Percent O*2*;

28.14 Percent CO*2*;

28.15 Percent Moisture—actual;

28.16 Dry Molecular Weight of Stack Gas;

28.17 Wet Molecular Weight of Stack Gas;

28.18 Stack Gas Velocity—fps; and

28.19 Stack Gas Flow Rate—dscfm.

29.0 *Point-Level Data Elements for EPA test Method 2.* For each run of each separate EPA test Method 2 test, you must report the Source ID (*i.e.,* Data Element 18.1), EPA Test Method (Data Element 28.2), Run Number (Data Element 28.3), and Run Begin Date (Data Element 28.5) and the following point-level data elements:

29.1 Traverse Point ID;

29.2 Stack Temperature; and

29.3 Differential Pressure Reading (ΔP).

30.0 *Run-Level Data Elements for EPA test Method 4.* When you make a separate EPA test Method 4 determination of the stack gas moisture content corresponding to a pollutant reference method test, *i.e.,* when data from the pollutant reference method cannot determine the moisture content, you must report the Source ID (*i.e.,* Data Element 18.1) and the following run-level data elements for each EPA test Method 4 test run:

30.1 Test Number;

30.2 EPA Test Method;

30.3 Run Number;

30.4 Number of Traverse Points;

30.5 Run Begin Date;

30.6 Run Start Time (clock time start);

30.7 Run End Date;

30.8 Run End Time (clock time end);

30.9 Barometric Pressure;

30.10 Calibration Coefficient of Dry Gas Meter (Y);

30.11 Volume of Water Collected in Impingers and Silica Gel;

30.12 Percent Moisture-actual;

30.13 Initial Reading of Dry Gas Meter Volume (dcf);

30.14 Final Reading of Dry Gas Meter Volume (dcf); and

30.15 Dry Gas Meter Temperature (average).

31.0 *Other Information for Each Test or Test Series.* You must provide each test included in the data file described in this appendix with supporting documentation, in a PDF file submitted concurrently with the data file, such that all the data required to be reported by § 63.7(g) are provided. That supporting data include but are not limited to diagrams showing the location of the test site and the sampling points, laboratory report(s) including analytical calibrations, calibrations of source sampling equipment, calibration gas cylinder certificates, raw instrumental data, field data sheets, quality assurance data (*e.g.*, field recovery spikes) and any required audit results and stack testers' credentials (if applicable). The applicable data elements in § 63.10031(f)(6)(i) through (xii) must be entered into the ECMPS reporting tool with each PDF submittal; the test number(s) (see § 63.10031(f)(6)(xi)) must be included. The test number(s) must match the test number(s) in sections 19 through 31 of this appendix (as applicable).

[85 FR 55775, Sept. 9, 2020, as amended at 91 FR 9132, Feb. 24, 2026; 91 FR 20369, Apr. 16, 2026]

Appendix J

40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Source:76 FR 15664, Mar. 21, 2011, unless otherwise noted.

What This Subpart Covers

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

[78 FR 7162, Jan. 31, 2013]

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in § 63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in § 63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater 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 or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers and process heaters as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72806, Nov. 20, 2015]

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of § 60.2145(a)(2) and (3) or § 60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

Emission Limitations and Work Practice Standards

§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b) through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3 and 11 through 15 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Table 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Table 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using Equation 1 of § 63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Table 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (iv) of this section, but on or after October 6, 2025, you must comply with the emission limits in Table 1 to this subpart. If you operate an existing boiler or process heater, you can choose to comply with alternative limits as discussed in paragraph (a)(1)(v) of this section, but on or after October 6, 2025 you must comply with the emission limits in Table 2 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 11 or 14 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction on or after May 20, 2011, and before December 23, 2011, you may comply with the emission limits in Table 12 or 14 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction on or after December 23, 2011, and before April 1, 2013, you may comply with the emission limits in Table 13 or 14 to this subpart until January 31, 2016.

(iv) If you operate a new boiler or process heater, you must comply with either the emission limits in Table 1 to this subpart or the emission limits in Table 14 to this subpart until you must comply with the emission limits in Table 1.

(v) If you operate an existing boiler or process heater, you must comply with either the emission limits in Table 2 to this subpart or the emission limits in Table 15 to this subpart until you must comply with the emission limits in Table 2.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to

the Administrator 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) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or Tables 11 through 15 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or Tables 11 through 15 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015; 87 FR 60840, Oct. 6, 2022]

§ 63.7501 [Reserved]

General Compliance Requirements

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard. Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Table 1 or 2 or Tables 11 through 15 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through the use of CPMS, or with a CEMS or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) 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 design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(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. 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 § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(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, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 10 to this subpart), (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.

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of "startup" in § 63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015; 87 FR 60841, Oct. 6, 2022]

Testing, Fuel Analyses, and Initial Compliance Requirements

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart through performance (stack) testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those Gas 1 fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those non-Gas 1 gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those non-Gas 1 fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraphs (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstrations, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013, or within 180 days after startup of the source, whichever is later.

(1) If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent than the applicable emission limit in Table 14 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 14 no later than July 29, 2016.

(2) If you are demonstrating compliance with an emission limit in Table 14 to this subpart that is less stringent than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than October 6, 2025.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7515(d) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7515(d).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 or 14 to this subpart, as applicable, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

(k) For affected sources, as defined in § 63.7490, that switch subcategories consistent with § 63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

[78 FR 7164, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015; 87 FR 60841, Oct. 6, 2022]

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 15 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 15 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 15).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on 1 day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than 1 year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

[78 FR 7165, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015; 87 FR 60842, Oct. 6, 2022]

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 15 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 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013; 87 FR 60842, Oct. 6, 2022]

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard. For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. 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, HCl, or TSM in Tables 1 and 2 or 11 through 15 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) You must obtain composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in § 63.7510(a), you must obtain a composite fuel sample during each performance test run.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period for sampling during performance stack testing.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop a site-specific fuel analysis plan for other gas 1 fuels according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the identification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart. When using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in § 63.7521(g)(2)(iii).

(h) You must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

[78 FR 7167, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015; 87 FR 60842, Oct. 6, 2022]

§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 or 15 to this subpart as specified in paragraphs (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on April 1, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on April 1, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 or 15 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c to this paragraph (e)(1) to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 or 15 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 to this paragraph (e)(2) as an alternative to using Equation 1a of paragraph (e)(1) of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 or 15 to this subpart that are in pounds per million Btu of heat input.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual electrical generation for the month if you are complying with the emission limits on an electrical generation (output) basis.

Where:

Where:

Where:

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

Where:

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

Where:

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) If requested, you must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in § 63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with § 63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to § 63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) If submitted upon request, the Administrator shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 or 15 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 to this paragraph (j)(1).

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013; 80 FR 72809, Nov. 20, 2015; 87 FR 60843, Oct. 6, 2022]

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (O_2) (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS including an O_2 (or CO_2) analyzer by the compliance date specified in § 63.7495. The CO and O_2 (or CO_2) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may determine compliance with the CO emissions limit using a CO_2 analyzer as the diluent monitor. If a CO_2 analyzer is used as the diluent monitor, EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, for the fuel type(s) being burned in the unit and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to calculate the emissions corrected to 3 percent O_2 using the measured CO_2 percentage, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The equations used to calculate the emissions, must also account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. The methodology used to calculate the CO emissions and the methodology used to account for any CO_2 being added to, or removed from the emissions gas stream shall be detailed and approved in the site-specific monitoring plan developed according to § 63.7505(d).

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO_2 analyzer is used); the site-specific monitoring plan developed according to § 63.7505(d); and the requirements in § 63.7540(a)(8) and this paragraph (a). Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and this paragraph (a) must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must collect emission data for CO concurrently using both the CO CEMS and Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be conducted at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with this paragraph (a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Table 1 or 2 or Tables 11 through 15 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(vi) When CO*2* is used to correct CO emissions and CO*2* is measured on a wet basis, if needed, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O*2* both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.*, a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (e.g., hourly average wet-and dry-basis O*2* values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or CO*2*) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO*2*) data concurrently. Collect at least four CO and oxygen (or CO*2*) CEMS data values representing 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.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO*2* percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (*e.g.*, bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(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. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.*, PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.*, check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to 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 (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see § 63.14).

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

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

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

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Table 1 or 2 or Tables 11 through 15 to this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect 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.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO_2 CEMS to demonstrate continuous compliance with the

HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

(1) The SO*2* CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (QA), the SO*2* CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO*2* CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO*2* data, you must operate the SO*2* CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO*2* data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO*2* concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO*2* data and do not use part 75 substitute data values.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013; 80 FR 72810, Nov. 20, 2015; 87 FR 60844, Oct. 6, 2022]

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

Where:

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

Where:

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

Where:

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

Where:

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

Where:

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

Where:

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

Where:

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

Where:

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Table 1 or 2 or Tables 11 through 15 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (“back half”) of the Method 5 particulate sampling train to demonstrate compliance with the PM standards in this subpart. This shall not preclude the permitting authority from requiring a determination of the “back half” for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vii) The operating limit for boilers or process heaters 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 § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(viii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO*2* CEMS is to install and operate the SO*2* according to the requirements in § 63.7525(m) establish a maximum SO*2* emission rate equal to the highest hourly average SO*2* measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

Where:

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

Where:

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

Where:

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

Where:

(d)[Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart, you must meet the work practice standard according to Table 3 to this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 to this subpart.

(i) If you opt to comply with the alternative SO*2* CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO*2* CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO*2* operating limit by collecting the maximum hourly SO*2* emission rate on the SO*2* CEMS during the paired 3-run test for HCl. The maximum SO*2* operating limit is equal to the highest hourly average SO*2* concentration measured during the HCl performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013; 80 FR 72811, Nov. 20, 2015; 87 FR 60845, Oct. 6, 2022]

§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 or 15 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at *https://www.epa.gov/ttn/atw/boiler/boilerpg.html*.

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.*, fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

Where:

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 in paragraph (f) of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 or 15 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this paragraph (f) to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 or 15 to this subpart.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015; 87 FR 60845, Oct. 6, 2022]

Continuous Compliance Requirements

§ 63.7535 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 § 63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater 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), and required monitoring system quality assurance or 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 recorded during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon

request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 15 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) 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 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7555(d), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established 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 § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 17 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established 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 § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) 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 alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no 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 alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Table 1 or 2 or Tables 11 through 15 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Table 1 or 2 or Tables 11 through 15 to this subpart at all times the affected unit is subject to numeric emission limits.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify (PM CEMS only), operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) 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;

(iii) 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). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO*X* requirement to which the unit is subject;

(v) 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; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) 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 or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, 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 used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in § 63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in § 63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in § 63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in § 63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established 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 § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Table 1 or 2 or Tables 11 through 15 to this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 15 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013, as amended at 80 FR 72813, Nov. 20, 2015; 87 FR 60846, Oct. 6, 2022]

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7182, Jan. 31, 2013]

Notification, Reports, and Records

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. For a new or reconstructed affected source that has reclassified to major source status, you must submit an Initial Notification not later 120 days after the source becomes subject to this subpart.

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

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at § 63.7495(b).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Table 1 or 2 or Tables 11 through 15 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) “This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in § 63.7540(a)(10)(i) through (vi).”

(ii) “This facility has had an energy assessment performed according to § 63.7530(e).”

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: “No secondary materials that are solid waste were combusted in any affected unit.”

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) 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, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories 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.

(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013; 80 FR 72814, Nov. 20, 2015; 85 FR 73913, Nov. 19, 2020; 85 FR 84262, Dec. 28, 2020; 87 FR 60846, Oct. 6, 2022]

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in § 63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

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

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 17 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO*2*, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of § 63.7555(d).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

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

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

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

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

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

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

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[78 FR 7183, Jan. 31, 2013, as amended at 80 FR 72814, Nov. 20, 2015]

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(3) For units in the limited use subcategory, 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 fuel use records for the days the boiler or process heater was operating.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. 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 satisfy the definition of processing in § 241.2 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 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 16 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 17 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(5) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 15 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

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

(7) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 18 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of “startup” in § 63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of “startup” in § 63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (*e.g.*, CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of “startup” in § 63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of “startup” in § 63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013; 80 FR 72816, Nov. 20, 2015; 87 FR 60846, Oct. 6, 2022]

§ 63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the 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 (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if 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 listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g), except as specified in § 63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, and alternative analytical methods requested under § 63.7521(b)(2).

(3) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under §§ 63.7500(a)(2) and 63.7522(g)(2).

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7186, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

§ 63.7575 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 the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

12-month rolling average means the arithmetic mean of the previous 12 months of valid fuel analysis data. The 12 months should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating.

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

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

Average annual heat input rate means total heat input divided by the hours of operation 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.

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

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 or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; 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.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam 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 are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

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

Clean dry biomass means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by 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 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 (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, 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.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

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 or downtime.

Deviation. (1) *Deviation* 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.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

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 § 60.14).

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.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) 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 MWe 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, 2012.

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 and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year 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), process heater(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, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year 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), process heater(s), and any on-site energy use system(s) accounting for at least 33 percent of the energy (*e.g.*, steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr 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), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (*e.g.*, steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production 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 practices means the 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.

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 includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: 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 other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 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 metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. 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 metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical 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 and has a published detection limit equal or lower than the methods listed in Table 6 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 boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

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

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

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

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 fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater 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, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

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.

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/bio-based solid fuel and 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 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

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

Light liquid includes distillate oil, biodiesel, or vegetable oil.

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

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, and vegetable oil.

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

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 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 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance 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 in ASTM D1835 (incorporated by reference, see § 63.14); 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 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*3*H*8*.

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 or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum mercury concentration of 40 micrograms/cubic meters of gas.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

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

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

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater 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.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

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. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater 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. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

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.

(vi) 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.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Regulated gas stream means an offgas stream that is routed to a boiler or process heater 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.

Rolling average means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in § 63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

Secondary material means the material as defined in § 241.2 of this chapter.

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

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

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

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

Startup means:

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

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

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1, 2, 14, or 15 to this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition, the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating (S*1*), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition (S*2*), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition (MW*3*) and would be calculated using Equation 1 to this definition. In the case of boilers supplying steam to one or more common headers, S*1*, S*2*, and MW*(3)* for each boiler would be calculated based on its (steam energy) contribution (fraction of total steam energy) to the common header.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler or process heater 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 or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or process heater 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 or process heater that replaces a temporary boiler or process heater 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 within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

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

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards or 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.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater 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, that is promulgated pursuant to section 112(h) of the Clean Air Act.

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015; 87 FR 60846, Oct. 6, 2022]

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters [c]

As stated in § 63.7500, you must comply with the following applicable emission limits:

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters c

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.1E-04 a lb per MMBtu of heat input	2.9E-04 a lb per MMBtu of steam output or 2.7E-03 a lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 a lb per MMBtu of heat input	8.7E-07 a lb per MMBtu of steam output or 1.1E-05 a lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen d, 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

		dry basis corrected to 3-percent oxygen, d 30-day rolling average)		
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/ others designed to burn wet biomass fuel	a. CO (or CEMS)	590 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	6.1E-01 lb per MMBtu of steam output or 6.5 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	1.4E-02 lb per MMBtu of steam output or 1.9E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/ others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.3E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (5.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (5.2E-03 lb per MMBtu of steam output or 7.0E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/ bio-based solids	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.1E-03 lb per MMBtu of heat input; or (8.4E-06 a lb per MMBtu of heat input)	5.0E-03 lb per MMBtu of steam output or 5.8E-02 lb per MWh; or (1.1E-05 a lb per MMBtu of steam output or 1.2E-04 a lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/ bio-based solids	a. CO (or CEMS)	220 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, d 10-day rolling average)	0.18 lb per MMBtu of steam output or 2.5 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (8.0E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (8.1E-03 lb per MMBtu of steam output or 1.2E-01 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, d 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.5E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	3.4E-03 lb per MMBtu of steam output or 3.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3-percent oxygen	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	2.0E-02 lb per MMBtu of steam output or 1.6E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	180 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a	0.22 lb per MMBtu of steam output or 2.0 lb per MWh; 3-run average	1 hr minimum sampling time.

		dry basis corrected to 3-percent oxygen d, 30-day rolling average)		
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.5E-04 a lb per MMBtu of heat input	1.7E-04 a lb per MMBtu of steam output or 2.1E-03 a lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 a lb per MMBtu of heat input	5.3E-07 a lb per MMBtu of steam output or 6.7E-06 a lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.9E-03 lb per MMBtu of heat input; or (6.1E-06 a lb per MMBtu of heat input)	2.1E-03 lb per MMBtu of steam output or 2.7E-02 lb per MWh; or (6.7E-6 a lb per MMBtu of steam output or 8.5E-5 a lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 a lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 a lb per MMBtu of steam output or 1.6E-02 a lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	7.3E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.3E-02 lb per MMBtu of steam output or 7.6E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

b Incorporated by reference, see § 63.14.

c If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in Table 11, 12, or 13 to this subpart until January 31, 2016. On and after

January 31, 2016, but before October 6, 2025 you may comply with the emission limits in Table 14 to this subpart. On and after October 6, 2025 you must comply with the emission limits in this Table 1.

d An owner or operator may determine compliance with the carbon monoxide emissions limit using CO*2* as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO*2* correction percentage for the fuel type burned in the unit and must also take into account that the 3-percent oxygen correction is to be done on a dry basis. The methodology must account for any CO*2* being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60847, Oct. 6, 2022]

Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters [d]

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.0E-02 lb per MMBtu of heat input	2.3E-02 lb per MMBtu of steam output or 0.26 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.4E-06 lb per MMBtu of heat input	6.2E-06 lb per MMBtu of steam output or 6.9E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	3.9E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.1E-02 lb per MMBtu of steam output or 4.8E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	150 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.6 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	1.1 lb per MMBtu of steam output or 13 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.4E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	4.0E-02 lb per MMBtu of steam output or 4.8E-01 lb per MWh; or (2.4E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 2 dscm per run.

8. Stokers/sloped grate/ others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (5.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (5.9E-03 lb per MMBtu of steam output or 7.0E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/ bio-based solid	a. CO (or CEMS)	210 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	2.1E-01 lb per MMBtu of steam output or 2.3 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.4E-03 lb per MMBtu of heat input; or (6.4E-05 lb per MMBtu of heat input)	9.2E-03 lb per MMBtu of steam output or 0.11 lb per MWh; or (8.0E-05 lb per MMBtu of steam output or 9.0E-04 lb per MWh)	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/ bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, c 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.1E-02 lb per MMBtu of heat input; or (8.0E-03 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 5.8E-01 lb per MWh; or (8.1E-03 lb per MMBtu of steam output or 0.12 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, c 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	2.5E-01 lb per MMBtu of steam output or 2.6 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	7.3E-07 lb per MMBtu of heat input	8.8E-07 lb per MMBtu of steam output or 1.1E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 b collect a minimum of 2 dscm.

15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.9E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.2E-02 lb per MMBtu of steam output or 8.2E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.2E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.7E-01 lb per MMBtu of steam output or 3.1 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	7.3E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.3E-02 lb per MMBtu of steam output or 7.6E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

b Incorporated by reference, see § 63.14.

c An owner or operator may determine compliance with the carbon monoxide emissions limit be determined using CO_2 as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit and must also take into account that the 3-percent oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

d Before October 6, 2025 you may comply with the emission limits in Table 15 to this subpart. On and after October 6, 2025], you must comply with the emission limits in this Table 2.

[87 FR 60849, Oct. 6, 2022]

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in § 63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.

maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/ furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units	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. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in § 63.7495 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 a. to e. appropriate for the on-site technical hours listed in § 63.7575:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 15 to this subpart during startup	a. You must operate all CMS during startup. b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis.
	c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using paragraph (1) of the definition of “startup” in § 63.7575, once you start firing fuels that are not clean fuels you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using paragraph (2) of the definition of “startup” in § 63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels a. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in § 63.7505(e).
	d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as

	specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart during shutdown	You must operate all CMS during shutdown. While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device.
	If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas.
	You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

a As specified in § 63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the "fuel firing + 1 hour" requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (e.g., scrubber).

[87 FR 60852, Oct. 6, 2022]

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

As stated in § 63.7500, you must comply with the applicable operating limits:

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

When complying with a numerical emission limit under Table 1, 2, 11, 12, 13, 14, or 15 of this subpart using . . .	**You must meet these operating limits. . .**
1. Wet PM scrubber control on a boiler or process heater not using a PM CPMS	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber a control on a boiler or process heater not using a HCl CEMS	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on a boiler or process heater not using a PM CPMS	a. Maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average); or
	b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS	a. This option is for boilers and process heaters that operate dry control systems (*i.e.*, an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (*i.e.*, dry ESP). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on a boiler or process heater not using a PM CPMS	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
7. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.
8. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O*2* analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen

	concentration measured during the CO performance test, as specified in Table 8. 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 § 63.7525(a).
9. SO*2* CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO*2* CEMS, maintain the 30-day rolling average SO*2* emission rate at or below the highest hourly average SO*2* concentration measured during the HCl performance test, as specified in Table 8.

a A wet acid gas scrubber is a control device that removes acid gases by contacting the combustion gas with an alkaline slurry or solution. Alkaline reagents include, but not limited to, lime, limestone and sodium.

[80 FR 72874, Nov. 20, 2015, as amended at 87 FR 60853, Oct. 6, 2022]

Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant . . .	**You must. . .**	**Using, as appropriate . . .**
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. a
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981. a
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the TSM emission concentration	Method 29 at 40 CFR part 60, appendix A-8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981. a
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.

	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981. a
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784. a
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981. a
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

a Incorporated by reference, see § 63.14.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013; 80 FR 72825, Nov. 20, 2015]

Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

To conduct a fuel analysis for the following pollutant . . .	**You must . . .**	**Using . . .**
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 a, or ASTM D7430 a, or ASTM D6883 a, or ASTM D2234/D2234M a (for coal) or EPA 1631 or EPA 1631E or ASTM D6323 a (for solid), or EPA 821-R-01-013 (for liquid or solid), or ASTM D4177 a (for liquid), or ASTM D4057 a (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B a (for solid samples), ASTM D2013/D2013M a (for coal), ASTM D5198 a (for biomass), or EPA 3050 a (for solid fuel), or EPA 821-R-01-013 a (for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 a (for coal) or ASTM E711 a (for biomass), or ASTM D5864 a for liquids and other solids, or ASTM D240 a or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 a, ASTM E871 a, or ASTM D5864 a, or ASTM D240 a, or ASTM D95 a (for liquid fuels), or ASTM D4006 a (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 a (for coal), EPA SW-846-7471B a or EPA 1631 or EPA 1631E a (for solid samples), or EPA SW-846-7470A a or EPA SW-846-7471B a (for liquid samples), or EPA 821-R-01-013 a (for liquid or solid), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	For fuel mixtures use Equation 8 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 a, or ASTM D7430 a, or ASTM D6883 a, or ASTM D2234/D2234M a (for coal) or ASTM D6323 a (for coal or biomass), ASTM D4177 a (for liquid fuels) or ASTM D4057 a (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B a (for solid samples), ASTM D2013/D2013M a (for coal), or ASTM D5198 a (for biomass), or EPA 3050 a or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 a (for coal) or ASTM E711 a (for biomass), ASTM D5864 a, ASTM D240 a or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 a or ASTM E871 a, or D5864 a, or ASTM D240 a, or ASTM D95 a (for liquid fuels), or ASTM D4006 a (for liquid fuels), or equivalent.
	f. Measure chlorine concentration in fuel sample	

		EPA SW-846-9250 a, ASTM D6721 a, ASTM D4208 a (for coal), or EPA SW-846-5050 a or ASTM E776 a (for solid fuel), or EPA SW-846-9056 a or SW-846-9076 a (for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	For fuel mixtures use Equation 7 in § 63.7530 and convert from chlorine to HCl by multiplying by 1.028.
3. Mercury Fuel Specification for other gas 1 fuels	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter, or	Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954 a, ASTM D6350 a, ISO 6978-1:2003(E) a, or ISO 6978-2:2003(E) a, or EPA-1631 a or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 a or equivalent.
4. TSM	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 a, or ASTM D7430 a, or ASTM D6883 a, or ASTM D2234/D2234M a (for coal) or ASTM D6323 a (for coal or biomass), or ASTM D4177 a, (for liquid fuels), or ASTM D4057 a (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B a (for solid samples), ASTM D2013/D2013M a (for coal), ASTM D5198 a or TAPPI T266 a (for biomass), or EPA 3050 a or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 a (for coal) or ASTM E711 a (for biomass), or ASTM D5864 a for liquids and other solids, or ASTM D240 a or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 a or ASTM E871 a, or D5864 a, or ASTM D240 a, or ASTM D95 a (for liquid fuels), or ASTM D4006 a (for liquid fuels), or ASTM D4177 a (for liquid fuels) or ASTM D4057 a (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample	ASTM D3683 a, or ASTM D4606 a, or ASTM D6357 a or EPA 200.8 a or EPA SW-846-6020 a, or EPA SW-846-6020A a, or EPA SW-846-6010C a, EPA 7060 a or EPA 7060A a (for arsenic only), or EPA SW-846-7740 a (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	For fuel mixtures use Equation 9 in § 63.7530.

a Incorporated by reference, see § 63.14.

[83 FR 56725, Nov. 14, 2018]

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits [a] [b]

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits a b

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, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests.
				(b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	c. Opacity	i. Establish a site-specific maximum opacity level	(1) Data from the opacity monitoring	(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests.

			system during the PM performance test	
				(b) Determine the average hourly opacity reading by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum effluent pH and flow rate operating limits according to § 63.7530(b)	(1) Data from the pH and liquid flow-rate monitors and the HCl performance test	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction, as defined in § 63.7575, to determine the required injection rate.
	c. Alternative Maximum SO_2 emission rate	i. Establish a site-specific maximum SO_2 emission rate operating limit according to § 63.7530(b)	(1) Data from SO_2 CEMS and the HCl performance test	(a) You must collect the SO_2 emissions data according to § 63.7525(m) during the most recent HCl performance tests.
				(b) The maximum SO_2 emission rate is equal to the highest hourly average SO_2 emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b)	(1) Data from the activated carbon rate monitors and mercury performance test	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, as defined in § 63.7575, to determine the required injection rate.
4. Carbon monoxide for which compliance is demonstrated by a performance test	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7530(b)	(1) Data from the oxygen analyzer system specified in § 63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average oxygen concentration by computing the hourly

				averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load 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 highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

a Operating limits must be confirmed or reestablished during performance tests.

b If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests. For maximum operating load, if you conduct multiple performance tests, you must set the maximum operating load at the lower of the maximum values established during the performance tests.

[87 FR 60853, Oct. 6, 2022]

Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

If you must meet the following operating limits or work practice standards . . .	**You must demonstrate continuous compliance by . . .**
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation.
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(7) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; 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 operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.

7. Electrostatic Precipitator Total Secondary Electric Power Input	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 15 to this subpart.
	d. Calculate the HCI, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 16, 17, and/or 18 in § 63.7530.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). 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 § 63.7525(a)(7).
	b. Reducing the data to 30-day rolling averages; and
	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to § 63.7520(c).
11. SO*2* emissions using SO*2* CEMS	a. Collecting the SO*2* CEMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO*2* CEMS emission rate to a level at or below the highest hourly SO*2* rate measured during the HCl performance test according to § 63.7530.

[78 FR 7204, Jan. 31, 2013, as amended at 80 FR 72829, Nov. 20, 2015; 87 FR 60855, Oct. 6, 2022]

Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	**The report must contain . . .**	**You must submit the report . . .**
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards for periods of startup and shutdown in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard for periods of startup and shutdown, during the reporting period, the report must contain the information in § 63.7550(d); and	
	d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e)	

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013; 80 FR 72830, Nov. 20, 2015]

Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

Citation	**Subject**	**Applies to subpart DDDDD**
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575

§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes, except § 63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.
§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
§ 63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
§ 63.8(g)	Reduction of monitoring data	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	

		No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for 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 startup, shutdown, or malfunction	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) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction 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)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) 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 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013; 80 FR 72830, Nov. 20, 2015]

Table 11 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis	a. Mercury	8.0E-07 a lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 4 dscm.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	a. Mercury	2.0E-06 lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 4 dscm.
4. Units design to burn coal/solid fossil fuel			Collect a minimum of 3 dscm per run.

	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	
5. Pulverized coal boilers designed to burn coal/ solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen , c 10-day rolling average)	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run
11. Fluidized bed units designed to burn biomass/ bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 a lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run
12. Suspension burners designed to burn biomass/ bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
			Collect a minimum of 3 dscm per run

	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	
16. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run
	b. Mercury.	4.8E-07 a lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 4 dscm.
17. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-03 a lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run
19. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run
20. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

b Incorporated by reference, see § 63.14.

c An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60855, Oct. 6, 2022]

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After May 20, 2011, and Before December 23, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E-06 a lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as

			specified in the method; for ASTM D6784 b collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
4. Stokers designed to burn coal/ solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, c 10-day rolling average)	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 a lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 a lb per MMBtu of heat input	

			For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03 a lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

b Incorporated by reference, see § 63.14.

c An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60857, Oct. 6, 2022]

Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before April 1, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E-07 a lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
	a. CO (or CEMS)		1 hr minimum sampling time.

3. Stokers designed to burn coal/ solid fossil fuel		130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, c 10-day rolling average)	
	b. Filterable PM (or TSM)	2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 a lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
9. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/ bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel	a. HCl	1.2E-03 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E-07 a lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample

			as specified in the method; for ASTM D6784 bcollect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel	a. CO (or CEMS)	130 a ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, c 1-day block average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 a lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, c 3-hour rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 bcollect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

b Incorporated by reference, see § 63.14.

c An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60859, Oct. 6, 2022]

Table 14 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters [c]

As stated in § 63.7500, you may continue to comply with the following applicable emission limits until October 6, 2025:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 a lb per MMBtu of heat input		For M29, collect a minimum of 4 dscm per run; for M30A or M30B,

			8.7E-07 a lb per MMBtu of steam output or 1.1E-05 a lb per MWh	collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3- percent oxygen, d 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/ others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/ others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/ bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 a lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 a lb per MMBtu of steam output or 1.2E-03 a lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/ bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, d 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of	Collect a minimum of 2 dscm per run.

			steam output or 9.1E-02 lb per MWh)	
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, d 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3-percent oxygen	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen, d 30-day rolling average)	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 a lb per MMBtu of heat input	5.3E-07 a lb per MMBtu of steam output or 6.7E-06 a lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 a lb per MMBtu of heat input)	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 a lb per MMBtu of steam output or 1.1E-03 a lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 a lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 a lb per MMBtu of steam output or 1.6E-02 a lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input		

			2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

b Incorporated by reference, see § 63.14.

c If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in Table 11, 12, or 13 to this subpart until January 31, 2016. On and after January 31, 2016, but before October 6, 2025 you may comply with the emission limits in this Table 14. On and after October 6, 2025, you must comply with the emission limits in Table 1 to this subpart.

d An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60860, Oct. 6, 2022]

Table 15 to Subpart DDDDD of Part 63—Alternative Emission Limits for Existing Boilers and Process Heaters [d]

As stated in § 63.7500, you may continue to comply with following emission limits until October 6, 2025:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run		1 hr minimum sampling time.

		average; or (340 ppm by volume on a dry basis corrected to 3- percent oxygen, c 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average	
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3- percent oxygen, c 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/ others designed to burn wet biomass fuel	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3-percent oxygen, c 30-day rolling average)	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/ others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/ bio-based solid	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3- percent oxygen, c 30-day rolling average)	4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)	1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/ bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, c 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, c 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)		5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh;	Collect a minimum of 2 dscm per run.

		2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3- percent oxygen, c 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06 lb per MMBtu of heat input	2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 b collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 b collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of three dscm per run.

a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515

are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

b Incorporated by reference, see § 63.14.

c An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

d Before October 6, 2025 you may comply with the emission limits in this Table 15. On and after October 6, 2025, you must comply with the emission limits in Table 2 to this subpart.

[87 FR 60863, Oct. 6, 2022]

Appendix K

40 CFR Part 60, Subpart KKKKa – Standards of Performance for Stationary Combustion Turbines

Subpart KKKKa—Standards of Performance for Stationary Combustion Turbines

Source:91 FR 1985, Jan. 15, 2026, unless otherwise noted.

Introduction

§ 60.4300a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after December 13, 2024.

Applicability

§ 60.4305a Does this subpart apply to my stationary combustion turbine?

(a) Except as provided for in § 60.4310a, you are subject to this subpart if you own or operate a stationary combustion turbine that commenced construction, modification, or reconstruction after December 13, 2024, and that has a base load rating equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h)). Any additional heat input from duct burners used with heat recovery steam generating (HRSG) units or fuel preheaters is not included in the heat input value used to determine the applicability of this subpart to a given stationary combustion turbine. However, this subpart does apply to emissions from any associated HRSG and duct burner(s) that are associated with a combustion turbine subject to this subpart.

(b) A stationary combustion turbine subject to this subpart is not subject to subpart GG or KKKK of this part.

(c) Duct burners are not subject to subpart D, Da, Db, or Dc of this part (as applicable) if the duct burner is used with a HRSG unit that is part of a combustion turbine that is subject to this subpart.

(d) If you own or operate a stationary combustion turbine (including a combined cycle combustion turbine or a CHP combustion turbine) that commenced construction, modification, or reconstruction on or before December 13, 2024, you may submit a written petition to the Administrator requesting that the stationary combustion turbine comply with the applicable requirements for modified units under this subpart as an alternative to complying with subpart GG or KKKK of this part, and with subparts D, Da, Db, and Dc of this part, as applicable. If the Administrator or delegated authority approves the petitioner's request, the affected facility must comply with the requirements for modified units under this subpart unless the stationary combustion turbine is reconstructed or replaced with a new facility in the future.

(e) If you own or operate a combined cycle combustion turbine or combined heat and power combustion turbine, and changes are made after December 13, 2024, to allow the existing combustion turbine to also operate in simple cycle mode and those changes are determined a modification for NSPS purposes, this subpart shall apply to the combustion turbine only as it operates in simple cycle mode, and not to its existing configuration in combined cycle mode.

§ 60.4310a What stationary combustion turbines are not subject to this subpart?

(a) An integrated gasification combined cycle electric utility steam generating unit subject to subpart Da of this part is not subject to this subpart.

(b) A stationary combustion turbine used in a combustion turbine test cell/stand, as defined in § 60.4420a, is not subject to this subpart.

(c) If any solid fuel is combusted in the HRSG, the HRSG is not subject to this subpart.

(d) Combustion turbines subject to title II of the Clean Air Act are not subject to this subpart.

[91 FR 1985, Jan. 15, 2026, as amended at 91 FR 43566, July 16, 2026]

Emission Standards

§ 60.4315a What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO*X*) and sulfur dioxide (SO*2*).

§ 60.4320a What NO*X* emissions standard must I meet?

(a) Except as provided for in paragraph (c) of this section, for each stationary combustion turbine you must not discharge into the atmosphere from the affected facility any gases that contain an amount of NO*X* that exceeds the applicable emissions standard and be in accordance with the requirements specified in paragraph (b) of this section. If you choose to use NO*X* CEMS, input-based emission rates and standards are determined on a 4-operating-hour rolling basis and output-based emission rates and standards are determined on a 30-operating-day rolling basis. Mass-based emission rates are determined on both a 4-operating-hour and 12-calendar-month rolling basis.

(b) For the purpose of determining compliance with the applicable emissions standard, you must also meet the requirements specified in paragraphs (b)(1) through (4) of this section, as applicable to your affected facility.

(1) The NO*X* emission standard that is applicable to your affected facility shall be determined on an operating-hour basis, unless you elect to use the alternative provided for in paragraph (b)(2) of this section. Determining the hourly NO*X* emission standards for your affected facility requires recording hourly data and maintaining records according to the requirements in § 60.4390a. For hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponds to the highest emissions standard. For example, if your affected facility operates at 70 percent or less of its base load rating for any portion of the hour, the emission limit(s) in table 1 to this subpart for combustion turbines operating at 70 percent or less of base load rating shall apply for that hour.

(2) As an alternative to the requirements specified in paragraph (b)(1) of this section, you may elect to use the lowest NO*X* emission standard that is applicable to your affected facility, as determined using table 1 to this subpart, for the entire required compliance period.

(3) During each operating hour when only natural gas is combusted, you must meet the NO*X* emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing natural gas for that operating hour. During each operating hour when the heat input (based on the HHV of the fuels) of the combustion turbine engine is less than 50 percent natural gas (*i.e.*, 50 percent or greater non-natural gas), as defined in § 60.4420a, at any point during an operating hour, you must meet the NO*X* emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing fuels other than natural gas for that operating hour. During each operating hour when the heat input to the combustion turbine engine is greater than 50 percent natural gas, as defined in § 60.4420a, during an entire operating hour while combusting some portion of non-natural gas fuels, you must meet the NO*X* emission standard as determined by prorating the applicable NO*X* standards, based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type.

(4) If you have two or more combustion turbine engines share a common stack, are connected to a single electric generator, or share a steam turbine, except as provided for in paragraph (b)(4)(i) of this section, you must monitor the hourly NO*X* emissions at the common stack in lieu of monitoring each combustion turbine separately. If you choose to comply with the output-based emissions standard, the hourly gross or net energy output (electric, thermal, or mechanical, as applicable) must be the sum of the hourly loads for the individual affected combustion turbines, and you must express the operating time as “stack operating hours” (as defined in 40 CFR 72.2). If you attain compliance with the most stringent applicable emission standard in table 1 or 2 to this subpart, as applicable, at the common stack, each affected combustion turbine sharing the stack is in compliance.

(i) As an alternative to the requirements in this paragraph (b)(4), you may either:

(A) Monitor each combustion turbine separately by measuring the NO*X* emissions prior to mixing in the common stack; or

(B) Apportion the NO*X* emissions based on the unit's heat input contribution to the total heat input associated with the common stack and the appropriate F-factors. If you chose to comply with the output-based standard, output from a common steam turbine shall be apportioned based on the heat input to each combustion turbine. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the NO*X* emissions. The Administrator may approve such alternate methods for apportioning the NO*X* emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(ii) [Reserved]

(c) Stationary combustion turbines that meet at least one of the specifications described in paragraphs (c)(1) through (4) of this section are exempt from the applicable NO*X* emission standard in paragraphs (a) and (b) of this section.

(1) An emergency combustion turbine, as defined in § 60.4420a;

(2) A stationary combustion turbine that, as determined by the Administrator or delegated authority, is used for the research and development of control techniques and/or efficiency improvements relevant to stationary combustion turbine emissions; or

(3) A stationary combustion turbine that combusts byproduct fuels for which a facility-specific NO*X* emissions standard has been established by the Administrator or delegated authority according to the requirements of paragraphs (c)(3)(i) and (ii) of this section is exempt from the emission limits specified in tables 1 and 2 to this subpart.

(i) You may request a facility-specific NO*X* emission standard by submitting a written request to the Administrator or delegated authority explaining why your affected facility, when combusting the byproduct fuel, is unable to comply with the applicable NO*X* emission standard determined using table 1 or 2 to this subpart.

(ii) If the Administrator or delegated authority approves the request, a facility-specific NO*X* emissions standard will be established in a manner that the Administrator or delegated authority determines to be consistent with minimizing NO*X* emissions.

(4) Military combustion turbines for use in other than a garrison facility and military combustion turbines installed for use as military training facilities.

(d) You must meet the applicable NO*X* emissions standard to your affected facility during all times that the affected facility is operating (including periods of startup, shutdown, and malfunction).

§ 60.4325a What emission limit must I meet for NO*X* if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in table 1 or 2 to this subpart. If your turbine operates below 70 percent of the base load rating at any point during an operating hour, the part load standard is applicable during the entire operating hour. For non-part load operating hours, if your stationary combustion turbine's heat input is greater than or equal to 50 percent fuels other than natural gas at any point during an operating hour, your combustion turbine must meet the corresponding limit for non-natural gas. For non-part load operating hours when your total heat input is greater than 50 percent natural gas while combusting some portion of non-natural gas fuels, you must meet the corresponding emissions standard as determined by prorating the applicable NO*X* standards, based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type.

§ 60.4330a What SO*2* emissions standard must I meet?

(a) Except as provided for in paragraphs (b) through (e) of this section, for each new, modified, or reconstructed stationary combustion turbine you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO*2* exceeding either:

(1) 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output; or

(2) 26 ng SO*2*/J (0.060 lb SO*2*/MMBtu) heat input.

(b) For each new, modified, or reconstructed stationary combustion turbine combusting 50 percent or more low-Btu gas per calendar month based on total heat input (using the HHV of the fuel), you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO*2* exceeding either:

(1) 650 milligrams of sulfur per standard cubic meter (mg/scm) (28 grains (gr) of sulfur per 100 standard cubic feet (scf)); or

(2) 65 ng SO*2*/J (0.15 lb SO*2*/MMBtu) heat input.

(c) For each new, modified, or reconstructed stationary combustion turbine located in a noncontinental area, you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO*2* exceeding either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO*2*/J (0.42 lb SO*2*/MMBtu) heat input.

(d) For each new, modified, or reconstructed stationary combustion turbine for which the Administrator determines that the affected facility does not have access to natural gas and that the removal of sulfur compounds from the fuel would cause more environmental harm than benefit, you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO*2* exceeding either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO*2*/J (0.42 lb SO*2*/MMBtu) heat input.

(e) A stationary combustion turbine subject to either subpart J or Ja of this part is not subject to the SO*2* performance standards in this subpart.

§ 60.4331a What are the requirements for operating a stationary temporary combustion turbine?

(a) Notwithstanding any other provision of this subpart, owners or operators of a small- or medium-size stationary combustion turbine (*i.e.*, a combustion turbine with a base load rating less than or equal to 850 MMBtu/h) at a single location for up to 24 consecutive months, may elect to be a temporary combustion turbine and comply with the requirements in paragraphs (b) through (e) of this section as an alternative to the otherwise applicable emission standards and monitoring, recordkeeping, and reporting requirements of this subpart.

(b) You must meet the NO*X* emissions standard for stationary temporary combustion turbines in table 1 to this subpart and the applicable SO*2* emissions standard in § 60.4330a.

(c) Compliance with the NO*X* emissions standard must be demonstrated through maintaining the documentation in paragraphs (c)(1) and (2) of this section on-site:

(1) Each stationary temporary combustion turbine in use at the location has a manufacturer's emissions guarantee at or below the full load NO*X* emissions standard in table 1 to this subpart; and

(2) Each such turbine has been performance tested at least once in the prior 5 years as meeting the NO*X* emissions standard in table 1 to this subpart.

(d) Compliance with the SO*2* emissions standard must be demonstrated through complying with the provisions in § 60.4372a.

(e) The conditions in paragraphs (e)(1) through (3) of this section apply in determining whether your stationary combustion turbine qualifies as a stationary temporary combustion turbine.

(1) The combustion turbine may only be located at the same stationary source (or group of stationary sources located within a contiguous area and under common control) for a total period of 24 consecutive months. This is the total period of residence time allowed after the turbine commences operation at the location, regardless of whether the turbine is in operation for the entire 24-consecutive-month period.

(2) Any temporary combustion turbine that replaces a temporary combustion turbine at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The relocation of a stationary temporary combustion turbine within a single stationary source (or group of stationary sources located within a contiguous area and under common control) while performing the same or similar function (*i.e.,* serving the same electric, mechanical, or thermal load) does not restart the 24-calendar month residence time period.

[91 FR 1985, Jan. 15, 2026, as amended at 91 FR 43566, July 16, 2026]

General Compliance Requirements

§ 60.4333a What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction.

(b) If you own or operate a stationary combustion turbine subject to a NO*X* emissions standard in § 60.4320a, you must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400a or § 60.4405a. Thereafter, unless you perform continuous monitoring consistent with § 60.4335a, § 60.4340a, or § 60.4345a, you must conduct subsequent performance tests according to the applicable requirements in paragraphs (b)(1) through (6) of this section.

(1) Except as provided for in paragraphs (b)(2) through (5) of this section, you must conduct subsequent performance tests within 14 calendar months of the date that the previous performance test was conducted.

(2) If the NO*X* emission result from the most recent performance test is less than or equal to 75 percent of the NO*X* emissions standard for the stationary combustion turbine, you may reduce the frequency of subsequent performance tests to 26 calendar months following the date the previous performance test was conducted. If the results of any subsequent performance test exceed 75 percent of the NO*X* emissions standard for the stationary combustion turbine, you must resume 14-calendar-month performance testing.

(3) An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days or 10 operating days, whichever is longer, after the next operating day. The Administrator or delegated authority must be notified of recommencement of operation consistent with § 60.4375a(d).

(4) If you own or operate an affected facility that has operated 168 operating hours or less, either in total or using a particular fuel, since the date on which the previous performance test was conducted, you may request that the otherwise required performance test be postponed until the affected facility has operated more than 168 operating hours, either in total or using a particular fuel, since the date on which the previous performance test was conducted. A request for an extension under this paragraph (b)(4) must be addressed to the relevant air division or office director of the appropriate Regional Office of the U.S. EPA as identified in § 60.4(a) for his or her approval at least 30 calendar days prior to the date on which the performance test is required to be conducted. If a postponement is approved, a performance test must be conducted within 45 calendar days after the day that the facility reaches 168 hours of operation since the date on which the previous performance test was conducted. When the facility has operated more than 168 operating hours since the date on which the previous performance test was conducted, the Administrator or delegated authority must be notified consistent with § 60.4375a(e).

(5) For a facility at which a group consisting of no more than five similar stationary combustion turbines (*i.e.,* same manufacturer and model number) is operated, you may request the use of a custom testing schedule by submitting a written request to the Administrator or delegated authority. The minimum requirements of the custom schedule include the conditions specified in paragraphs (b)(5)(i) through (v) of this section.

(i) Emissions from the most recent performance test for each individual affected facility are 75 percent or less of the applicable standard;

(ii) Each stationary combustion turbine uses the same emissions control technology;

(iii) Each stationary combustion turbine is operated in a similar manner;

(iv) Each stationary combustion turbine and its emissions control equipment are maintained according to the manufacturer's recommended maintenance procedures; and

(v) A performance test is conducted on each affected facility at least once every 5 calendar years.

(6) A stationary combustion turbine subject to a NO*X* emissions standard in § 60.4320a that exchanges the combustion turbine engine for an overhauled combustion turbine engine as part of an exchange program, must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400a or § 60.4405a. (as applicable).

(c) Except as provided for in paragraph (c)(1) or (2) of this section, for each stationary combustion turbine subject to a NO*X* emissions standard in § 60.4320a, you must demonstrate continuous compliance using a continuous emissions monitoring system (CEMS) for measuring NO*X* emissions according to the provisions in § 60.4345a. If your stationary combustion turbine is equipped with a NO*X* CEMS, those measurements must be used to determine excess emissions.

(1) If your stationary combustion turbine uses water or steam injection but not post-combustion controls to meet the applicable NO*X* emissions standard in § 60.4320a, you may elect to demonstrate continuous compliance using the pounds per million British thermal units (lb/MMBtu) or parts per million (ppm) input-based standard according to the provisions in § 60.4335a.

(2) If your stationary combustion turbine does not use water injection, steam injection, or post-combustion controls to meet the applicable NO*X* emissions standard in § 60.4320a, you may elect to demonstrate continuous compliance with an input-based standard according to the provisions in § 60.4340a.

(d) An owner or operator of a stationary combustion turbine subject to an SO*2* emissions standard in § 60.4330a must demonstrate compliance using one of the methods specified in paragraphs (d)(1) through (4) of this section.

(1) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, you must conduct subsequent performance tests within 12 calendar months following the date the previous performance test was conducted. An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days after the next operating day;

(2) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, conduct subsequent fuel sulfur analyses using the applicable methods specified in § 60.4360a and at the frequency specified in § 60.4370a;

(3) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, maintain records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the initial and subsequent fuel combusted in your stationary combustion turbine at all times does not exceed applicable conditions specified in § 60.4370a or § 60.4372a; or

(4) Conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4415a. Thereafter, continue to monitor SO*2* emissions using a CEMS according to the requirements specified in § 60.4374a.

(e) If you elect to comply with an input-based standard (lb/MMBtu or ppm) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO*X* and SO*2* emission standards according to the procedures specified in paragraph (e)(1) or (2) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the fuel flow to the combustion turbine engine and any associated duct burners.

(2) For a configuration where two or more combustion turbine engines are exhausted through a single heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit and the total fuel flow to each combustion turbine engine and any associated duct burners. The applicable emissions standard for the affected facility is equal to the prorated (by heat input) emissions standards of each of the individual combustion turbine engines that are exhausted through the single heat recovery steam generating unit.

(f) If you elect to comply with an output-based standard (lb/MWh) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO*X* and SO*2* emission standards according to the procedures in paragraph (f)(1), (2), or (3) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the total electrical, mechanical energy, and useful thermal output of the stationary combustion turbine (as applicable).

(2) For a configuration where two or more combustion turbine engines are exhausted through a single heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit, and the total electrical, mechanical energy, and useful thermal output of the heat recovery steam generating unit and each combustion turbine engine (as applicable). The applicable emissions standard for the affected facility is equal to the most stringent emissions standard for any individual combustion turbine engines.

(3) For a configuration where your combustion turbine engines are exhausted through two or more heat recovery steam generating units which serve a common steam turbine or steam header, you must measure both the emissions at the exhaust stack for each heat recovery steam generating unit and the total electrical or mechanical energy output of each combustion turbine engine (as applicable). To determine

the net or gross energy output of the steam produced by the heat recovery steam generating unit, you must develop a custom method and provide information, satisfactory to the Administrator or delegated authority, apportioning the net or gross energy output of the steam produced by the heat recovery steam generating units to each of the affected stationary combustion turbines.

(g) If you elect to comply with the mass-based standard, you must demonstrate continuous compliance using either a CEMS for measuring NO*X* emissions according to the provisions in § 60.4345a or using the methodology in appendix E to part 75 of this chapter.

[91 FR 1985, Jan. 15, 2026, as amended at 91 FR 43566, July 16, 2026]

Monitoring

§ 60.4335a How do I demonstrate compliance with my NO*X* emissions standard without using a NO*X* CEMS if I use water or steam injection?

If you qualify and elect to demonstrate continuous compliance according to the provisions of § 60.4333a(c)(1), you must install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the fuel consumption and the water or steam to fuel ratio fired in the combustion turbine engine consistent with the requirements in § 60.4342a. Water or steam only needs to be injected when a fuel is being combusted that requires water or steam injection for compliance with the applicable NO*X* emissions standard.

§ 60.4340a How do I demonstrate compliance with my NO*X* emissions standard without using a NO*X* CEMS if I do not use water or steam injection?

(a) If you qualify and elect to demonstrate continuous compliance according to the provisions of § 60.4333a(c)(2), you must demonstrate compliance with the NO*X* emissions standard using one of the methods specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct performance tests according to requirements in § 60.4400a;

(2) Monitor the NO*X* emissions rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19 of this chapter; or

(3) Install, calibrate, maintain, and operate an operating parameter continuous monitoring system according to the requirements specified in paragraph (b) of this section and consistent with the requirements specified in § 60.4342a.

(b) If you opt to demonstrate compliance according to the procedures described in paragraph (a)(3) of this section, continuous operating parameter monitoring must be performed using the methods specified in paragraphs (b)(1) through (4) of this section as applicable to the stationary combustion turbine.

(1) Selection of the operating parameters used to comply with this paragraph (b) must be identified in the performance test report. The selection of operating parameters is subject to the review and approval of the Administrator or delegated authority.

(2) For a lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO*X* mode during periods when low-NO*X* operation is required to comply with the applicable emission NO*X* standard.

(3) For a stationary combustion turbine other than a lean premix stationary combustion turbine, you must define parameters indicative of the unit's NO*X* formation characteristics and monitor these parameters continuously.

(4) You must perform the parametric monitoring described in section 2.3 in appendix E to part 75 of this chapter or in § 75.19(c)(1)(iv)(H) of this chapter.

§ 60.4342a How do I monitor NO*X* control operating parameters?

(a) If you monitor steam or water to fuel ratio according to § 60.4335a or other parameters according to § 60.4340a, the applicable parameters must be continuously monitored and recorded during the performance test, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations, and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO*X* emission controls. The plan must include the information specified in paragraphs (a)(1) through (6) of this section:

(1) Identification of the parameters to be monitored and show there is a significant relationship to emissions and proper operation of the NO*X* emission controls;

(2) Selected parameter ranges (or designated conditions) indicative of proper operation of the stationary combustion turbine NO*X* emission controls, or describe the process by which such range (or designated condition) will be established;

(3) Explanation of the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable);

(4) Description of quality assurance and control practices used to ensure the continuing validity of the data;

(5) Description of the frequency of monitoring and the data collection procedures which you will use (*e.g.*, you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred); and

(6) Justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges.

(b) The water or steam to fuel ratio and parameter continuous monitoring system ranges must be confirmed or reestablished at least once every 60 calendar months following the previous calibration and each time the combustion turbine engine is replaced with an overhauled turbine engine as part of an exchange program. An affected facility that has not operated for 60 calendar days prior to the due date of a recalibration or has had the combustion turbine replaced with an overhauled turbine engine as part of an exchange program is not required to perform the subsequent recalibration until 45 calendar days after the next operating day.

§ 60.4345a How do I demonstrate compliance with my NO*X* emissions standard using a NO*X* CEMS?

(a) Each CEMS measuring NO*X* emissions used to meet the requirements of this subpart, must meet the requirements in paragraphs (a)(1) through (6) of this section.

(1) You must install, certify, maintain, and operate a NO*X* monitor to determine the hourly average NO*X* emissions in the units of the standard with which you are complying.

(2) If you elect to comply with an input-based or mass-based emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O*2* or CO*2* CEMS and a stack flow monitor to continuously measure the heat input to the affected facility.

(3) If you elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate both a watt meter (or meters) to continuously measure the gross electrical output from the affected facility and either a fuel flow meter (or flow meters) or an O*2* or CO*2* CEMS and a stack flow monitor. If you have a CHP combustion turbine and elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate meters to continuously determine the total useful recovered thermal energy. For steam this includes flow rate, temperature, and pressure. If you have a direct mechanical drive application and elect to comply with the output-based emissions standard you must submit a plan to the Administrator or delegated authority for approval of how energy output will be determined.

(4) If you elect to comply with the part-load NO*X* emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O*2* or CO*2* CEMS and a stack flow monitor to continuously measure the heat input to the affected facility.

(5) If you elect to comply with the temperature dependent NO*X* emissions standard, you must install, calibrate, maintain, and operate a thermometer to continuously monitor the ambient temperature.

(6) If you combust natural gas with fuels other than natural gas and elect to comply with the fuels other than natural gas NO*X* emissions standard, you must install, calibrate, maintain, and operate a device to continuously monitor when a fuel other than natural gas fuel is combusted in the combustion turbine engine.

(b) Each NO*X* CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part. The span value must be 125 percent of the highest applicable standard or highest anticipated hourly NO*X* emissions rate. Alternatively, span values determined according to section 2.1.2 in appendix A to part 75 may be used. For stationary combustion turbines that do not use post-combustion technology to reduce emissions of NO*X* to comply with the requirements of this subpart, you may use NO*X* and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. For stationary combustion turbines that use post-combustion technology to reduce emissions of NO*X* to comply with the requirements of this subpart, you may use NO*X* and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13 with approval from the Administrator or delegated authority, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis.

(c) During each full operating hour, both the NO*X* monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour. For partial operating hours, at least one data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two data points (one in each of two quadrants) are required for each monitor.

(d) Each fuel flow meter must be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements in appendix D to part 75 of this chapter are acceptable for use under this subpart.

(e) Each watt meter, steam flow meter, and each pressure or temperature measurement device must be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(f) You must develop, submit to the Administrator or delegated authority for approval, maintain, and adhere to an on-site quality assurance (QA) plan for all of the continuous monitoring equipment you use to comply with this subpart. At a minimum, such a QA plan must address the requirements of § 60.13(d), (e), and (h). For the CEMS and fuel flow meters, the owner or operator of a stationary combustion turbine that does not use post-combustion technology to reduce emissions of NO*X* to comply with the requirements of this subpart may, with approval of the Administrator or delegated authority, satisfy the requirements of this paragraph (f) by implementing the QA program and plan described in section 1 in appendix B to part 75 of this chapter in lieu of the requirements in § 60.13(d)(1).

(g) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating-day rolling average basis.

§ 60.4350a How do I use the NO*X* CEMS data to determine excess emissions?

(a) If you demonstrate continuous compliance using a CEMS for measuring NO*X* emissions, excess emissions are defined as the applicable compliance period for the stationary combustion turbine (either 4-operating-hours, 30-operating-days, or 12-calendar-month), during which the average NO*X* emissions from your affected facility measured by the CEMS is greater than the applicable maximum allowable NO*X* emissions standard specified in § 60.4320a as determined using the procedures specified in this section that apply to your stationary combustion turbine.

(b) The NO*X* CEMS data for each operating hour as measured according to the requirements in § 60.4345a must be used to determine the hourly average NO*X* emissions. The hourly average for a given operating hour is the average of all data points for the operating hour. However, for any periods during which the NO*X*, diluent, flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the hourly average NO*X* emissions. All data points that are not collected during out-of-control periods must be used to determine the hourly average NO*X* emissions.

(c) For each operating hour in which an hourly average is obtained, the data acquisition and handling system must calculate and record the hourly average NO*X* emissions in units of lb/MMBtu or lbs, as applicable, using the appropriate equation from EPA Method 19 in appendix A-7 to this part. For any hour in which the hourly average O*2* concentration exceeds 19.0 percent O*2* (or the hourly average CO*2* concentration is less than 1.0 percent CO*2*), a diluent cap value of 19.0 percent O*2* or 1.0 percent CO*2* (as applicable) may be used in the emission calculations.

(d) Data used to meet the requirements of this subpart shall not include substitute data values derived from the missing data procedures of part 75 of this chapter, nor shall the data be bias adjusted according to the procedures of part 75 of this chapter. For units complying with the 12-calendar-month mass-based standard, emissions for hours of missing data shall be estimated by using the average emissions rate of non-out-of-control hours within ±10 percent of the hourly load value of missing data within the 12-calendar-month period. If non-out-of-control data is not available, the maximum hourly emissions rate during the 12-calendar-month period shall be used.

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. However, for any periods during which the flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the appropriate hourly average value.

(f) Calculate the hourly average NO*X* emissions rate, in units of the emissions standard under § 60.4320a, using lb/MMBtu or ppm for units complying with the input-based standard, using lbs for units complying with the mass-based standard, or lb/MWh or kg/MWh for units complying with the output-based standard:

(1) The gross or net energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine engine; the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit; the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, minus the auxiliary load as calculated using equations 1 and 2 to this paragraph (f)(1):

Equation 2 to Paragraph (f)(1)

(2) For mechanical drive applications complying with the output-based standard, use equation 3 to this paragraph (f)(2):

Equation 3 to Paragraph (f)(2)

(g) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess NO*X* emissions are determined on a 4-operating-hour averaging period basis using the NO*X* CEMS data and procedures specified in paragraphs (g)(1) and (2) of this section as applicable to the NO*X* emissions standard in table 1 to this subpart.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling average NO*X* emissions as the heat input weighted average of the hourly average of NO*X* emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (g)(2) of this section. Calculate a 4-operating-hour rolling average NO*X* emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.*, a valid 4-operating-hour rolling average NO*X* emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average NO*X* emissions rate and the applicable 4-operating-hour rolling average NO*X* emissions standard, calculated using hourly values in table 1 to this subpart, using equation 4 to this paragraph (g)(2).

Equation 4 to Paragraph (g)(2)

(h)(1) For each combustion turbine demonstrating compliance on an output-based standard, you must determine excess emissions on a 30-operating-day rolling average basis. The measured emissions rate is the NO*X* emissions measured by the CEMS for a given operating day and the 29 operating days preceding that day. Once each day, calculate a new 30-operating-day average measured emissions rate using all hourly average values based on non-out-of-control NO*X* emission data for all operating hours during the previous 30-operating-day operating period. Report any 30-operating-day periods for which you have less than 90 percent data availability as monitor downtime. If you elect to comply with the applicable output-based emissions rate standard, calculate the measured emissions rate using equation 5 to this paragraph (h)(1) and calculate the applicable emissions standard using equation 6 to this paragraph (h)(1). If you elect to comply with the applicable output-based emissions rate standard and determine the heat input on an hourly basis, calculate the 30-operating-day rolling average NO*X* emissions rate using equation 5, and determine the applicable 30-operating-day rolling average NO*X* emissions standard, calculated using values in table 1 to this subpart, using equation 6. Hours are not subcategorized by load for the purposes of determining the applicable output-based standard. The emissions standard for all hours, regardless of load, is the otherwise applicable full load emissions standard.

Equation 5 to Paragraph (h)(1)

Equation 6 to Paragraph (h)(1)

(2) If you elect to comply with the applicable output-based emissions rate standard and elect to not determine the heat input on an hourly basis, the applicable 30-operating-day emissions rolling NO*X* standard is the most stringent standard applicable to the combustion turbine. The 30-operating-day rolling NO*X* emissions rate is determined as the sum of the hourly emissions divided by the sum of the gross or net output over the 30-operating-day period.

(i) For each combustion turbine demonstrating compliance on a mass-based standard, you must determine excess NO*X* emissions on both a rolling 4-operating-hour and rolling 12-calendar-month basis using the NO*X* CEMS data and procedures specified in paragraphs (i)(1) through (4) of this section as applicable to the NO*X* emissions standard in table 2 to this subpart. In addition, during system emergencies each combustion turbine must determine excess NO*X* emissions using the procedures specified in paragraph (i)(5) of this section.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling NO*X* emissions as the sum of the hourly NO*X* emissions for a given operating hour and the 3 operating hours preceding that operating hour. Calculate a 4-operating-hour NO*X* emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.*, a valid 4-operating-hour rolling NO*X* emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) Calculate the applicable 4-operating-hour rolling NO*X* emissions standard, calculated using hourly values in table 2 to this subpart, using equation 7 to this paragraph (i)(2).

Equation 7 to Paragraph (i)(2)

(3) For each 12-calendar-month period, compute the 12-calendar-month rolling NO*X* emissions as the sum of the hourly NO*X* emissions for a given month and the 11 calendar months preceding the calendar month. Emissions during system emergencies are not included when calculating the 12-calendar-month emissions rate.

(4) Calculate the applicable 12-calendar-month rolling NO*X* emissions standard, calculated using hourly values in table 2 to this subpart, using equation 8 to this paragraph (i)(4). Heat input during system emergencies is not included when calculating the 12-calendar-month emissions standard.

Equation 8 to Paragraph (i)(4)

(5) During system emergencies during which the owner or operator elects to not include emissions or heat input in the 12-calendar month calculations, the applicable average natural gas-fired emissions standard is 0.83 lb NO*X*/MW-rated output (1.8 lb NO*X*/MW-rated output when firing non-natural gas) or the current emissions rate necessary to comply with the 12-calendar month natural gas-fired emissions standard of 0.48 tons NO*X*/MW-rated output (0.81 tons NO*X*/MW-rated output when firing non-natural gas) whichever is more stringent. For example, if a combustion turbine operated for 4,000 hours during the current 12-calendar month period the applicable average natural gas-fired emissions standard during the system emergency would be 0.24 lb NO*X*/MW-rated output and the applicable average non-natural gas-fired emissions standard during the system emergency would be 0.41 lb NO*X*/MW-rated output.

[91 FR 1985, Jan. 15, 2026, as amended at 91 FR 43566, July 16, 2026]

§ 60.4360a How do I use fuel sulfur analysis to determine the total sulfur content of the fuel combusted in my stationary combustion turbine?

(a) If you elect to demonstrate compliance with a SO_2 emissions standard according to § 60.4333a(d)(2), the fuel analyses may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency as determined by the Administrator or delegated authority using the sampling frequency specified in § 60.4370a.

(b) Representative fuel analysis samples may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287-97 (Reapproved 2002) (incorporated by reference, see § 60.17) for gaseous fuels or ASTM D4177-95 (Reapproved 2000) (incorporated by reference, see § 60.17) for liquid fuels. For reference purposes when manually collecting gaseous samples, see Gas Processors Association Standard 2166-17 (incorporated by reference, see § 60.17). For reference purposes when manually collecting liquid samples, see either Gas Processors Association Standard 2174-14 or the procedures for manual pipeline sampling in section 14 of ASTM D4057-95 (Reapproved 2000) (both of which are incorporated by reference, see § 60.17).

(c) Each collected fuel analysis sample must be analyzed for the total sulfur content of the fuel and heating value using the methods specified in paragraph (c)(1) or (2) of this section, as applicable to the fuel type.

(1) For the sulfur content of liquid fuels, ASTM D129-00 (Reapproved 2005), or alternatively D1266-98 (Reapproved 2003), D1552-03, D2622-05, D4294-03, D5453-05, D5623-24, or D7039-24 (all of which are incorporated by reference, see § 60.17). For the heating value of liquid fuels, ASTM D240-19 or D4809-18 (both of which are incorporated by reference, see § 60.17); or

(2) For the sulfur content of gaseous fuels, ASTM D1072-90 (Reapproved 1999), or alternatively D3246-05, D4468-85 (Reapproved 2000), D6667-04, or D5504-20 (all of which are incorporated by reference, see § 60.17). If the total sulfur content of the gaseous fuel during the most recent compliance demonstration was less than half the applicable standard, ASTM D4084-05, D4810-88 (Reapproved 1999), D5504-20, or D6228-98 (Reapproved 2003), or Gas Processors Association Standard 2140-17 or 2377-86 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used. For the heating value of gaseous fuels, ASTM D1826-94 (Reapproved 2003), or alternatively D3588-98 (Reapproved 2003), D4891-89 (Reapproved 2006), or Gas Processors Association Standard 2172-09 (all of which are incorporated by reference, see § 60.17).

§ 60.4370a How frequently must I determine the fuel sulfur content?

(a) If you are complying with requirements in § 60.4360a, the total sulfur content of all fuels combusted in each stationary combustion turbine subject to an SO_2 emissions standard in § 60.4330a must be determined according to the schedule specified in paragraph (a)(1) or (2) of this section, as applicable to the fuel type, unless you determine a custom schedule for the stationary combustion turbine according to paragraph (b) of this section.

(1) Use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 in appendix D to part 75 of this chapter (*i.e.,* flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank or sampling each delivery prior to combining it with liquid fuel already in the intended storage tank).

(2) If the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per operating day.

(b) As an alternative to the requirements of paragraph (a) of this section, you may implement custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply using the procedures provided in either paragraph (b)(1) or (2) of this section. Either you or the fuel vendor may perform the sampling. As an alternative to using one of these procedures, you may use a custom schedule that has been substantiated with data and approved by the Administrator or delegated authority as a change in monitoring prior to being used to comply with the applicable standard in § 60.4330a.

(1) You may determine and implement a custom sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) Obtain daily total sulfur content measurements for 30 consecutive operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content must be as specified in paragraph (b)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals provided the fuel source or supplier does not change. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable standard, follow the procedures in paragraph (b)(1)(iii) of this section. If any measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable standard, but none exceeds the applicable standard, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable standard, immediately begin daily monitoring according to paragraph (b)(1)(i) of this section. Daily monitoring must continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable standard, are obtained. At that point, the applicable procedures of paragraph (b)(1)(ii) or (iii) of this section must be followed.

(2) You may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 in appendix D to part 75 of this chapter to determine and implement a sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) If the maximum fuel sulfur content obtained from any of the 720 hourly samples does not exceed half the applicable standard, then the minimum required sampling frequency must be one sample at 12-month intervals.

(ii) If any sample result exceeds half the applicable standard, but none exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iii) of this section.

(iii) If the sulfur content of any of the 720 hourly samples exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iv) of this section.

§ 60.4372a How can I demonstrate compliance with my SO*2* emissions standard using records of the fuel sulfur content?

(a) If you elect to demonstrate compliance with a SO*2* emissions standard according to § 60.4333a(d)(3), you must maintain on-site records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the fuel combusted in your stationary combustion turbine at all times does not exceed the conditions specified in paragraph (b) through (e) of this section, as applicable to your stationary combustion turbine.

(b) If your stationary combustion turbine is subject to the SO*2* emissions standard in § 60.4330a(a), then the fuel combusted must have a potential SO*2* emissions rate of 26 ng/J (0.060 lb/MMBtu) heat input or less.

(c) If your stationary combustion turbine is subject to the SO*2* emissions standard in § 60.4330a(b), then the total sulfur content of the gaseous fuel combusted must be 650 (mg/scm) (28 gr/100 scf).

(d) If your stationary combustion turbine is subject to the SO*2* emissions standard in § 60.4330a(c) or (d), the total sulfur content of the fuel combusted must be:

(1) For natural gas, 140 gr/100 scf or less.

(2) For fuel oil, 0.40 weight percent (4,000 ppmw) or less.

(3) For other fuels, potential SO*2* emissions of 180 ng/J (0.42 lb/MMBtu) heat input or less.

(e) Representative fuel sampling data following the procedures specified in section 2.3.1.4 or 2.3.2.4 in appendix D to part 75 of this chapter documenting that the fuel meets the part 75 requirements to be considered either pipeline natural gas or natural gas. Your stationary combustion turbine may not cause to be discharged into the atmosphere any gases that contain SO*2* in excess of:

(1) 110 ng SO*2*/J (0.90 lb SO*2*/MWh) gross energy output or 26 ng SO*2*/J (0.060 lb SO*2*/MMBtu) heat input; or

(2) 780 ng SO*2*/J (6.2 lb SO*2*/MWh) gross energy output or 180 ng SO*2*/J (0.42 lb SO*2*/MMBtu) heat input if your combustion turbine is in a noncontinental area.

§ 60.4374a How do I demonstrate compliance with my SO*2* emissions standard and determine excess emissions using a SO*2* CEMS?

(a) If you demonstrate continuous compliance using a CEMS for measuring SO*2* emissions, excess emissions are defined as the applicable averaging period, either 4-operating-hour or 30-operating-day, during which the average SO*2* emissions from your stationary combustion turbine measured by the CEMS exceeds the applicable SO*2* emissions standard specified in § 60.4330a as determined using the procedures specified in this section that apply to your stationary combustion turbine.

(b) You must install, calibrate, maintain, and operate a CEMS for measuring SO*2* concentrations and either O*2* or CO*2* concentrations at the outlet of your stationary combustion turbine, and record the output of the system.

(c) The 1-hour average SO*2* emissions rate measured by a CEMS must be expressed in ng/J or lb/MMBtu heat input and must be used to calculate the average emissions rate under § 60.4330a.

(d) You must use the procedures for installation, evaluation, and operation of the CEMS as specified in § 60.13 and paragraphs (d)(1) through (3) of this section.

(1) Each CEMS must be operated according to the applicable procedures under Performance Specifications 1, 2, and 3 in appendix B to this part;

(2) Quarterly accuracy determinations and daily calibration drift tests must be performed according to Procedure 1 in appendix F to this part; and

(3) The span value of the SO*2* CEMS at the outlet from the SO*2* control device (or outlet of the stationary combustion turbine if no SO*2* control device is used) must be 125 percent of either the highest applicable standard or highest potential SO*2* emissions rate of the fuel combusted. Alternatively, SO*2* span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(e) If you have installed and certified a SO*2* CEMS that meets the requirements of part 75 of this chapter, the Administrator or delegated authority can approve that only quality assured data from the CEMS must be used to identify excess emissions under this subpart. You must report periods where the missing data substitution procedures in subpart D of part 75 are applied as monitoring system downtime in the excess emissions and monitoring performance report required under § 60.7(c).

(f) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(g) Calculate the hourly average SO*2* emissions rate, in units of the emissions standard under § 60.4330a, using lb/MMBtu for units complying with the input-based standard or using equation 1 to paragraph (g)(1) of this section for units complying with the output-based standard:

(1) For simple cycle operation:

Equation 1 to Paragraph (g)(1)

(2) The gross or net energy output is calculated as the sum of the total electrical and mechanical energy generated by the stationary combustion turbine; the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit; the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, minus the auxiliary load as calculated using equations 2 and 3 to this paragraph (g)(2); and any auxiliary load.

Equation 3 to Paragraph (g)(2)

(3) For mechanical drive applications complying with the output-based standard, use equation 4 to this paragraph (g)(3):

Equation 4 to Paragraph (g)(3)

(h) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess SO*2* emissions are determined on a 4-operating-hour averaging period basis using the SO*2* CEMS data and procedures specified in paragraphs (i)(1) and (2) of this section and as applicable to the SO*2* emission standard.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling average SO*2* emissions as the heat input weighted average of the hourly average of SO*2* emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (i)(2) of this section. Calculate a 4-operating-hour rolling average SO*2* emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.,* a valid 4-operating-hour rolling average SO*2* emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average SO*2* emissions rate and the applicable 4-operating-hour rolling average SO*2* emission standard using equation 5 to this paragraph (h)(2).

Equation 5 to Paragraph (h)(2)

(i) For each combustion turbine demonstrating compliance on an output-based standard, you must determine excess emissions on a 30-operating-day rolling average basis. The measured emissions rate is the SO*2* emissions measured by the CEMS for a given operating day and the 29 operating days preceding that day. Once each operating day, calculate a new 30-operating-day average measured emissions rate using all hourly average values based on non-out-of-control SO*2* emission data for all operating hours during the previous 30-operating-day operating period. Report any 30-operating-day periods for which you have less than 90 percent data availability as monitor downtime. Calculate both the 30-operating-day rolling average SO*2* emissions rate and the applicable 30-operating-day rolling average SO*2* emissions standard using equation 6 to this paragraph (i).

Equation 6 to Paragraph (i)

(j) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating-day rolling average basis.

[91 FR 1985, Jan. 15, 2026, as amended at 91 FR 43567, July 16, 2026]

Recordkeeping and Reporting

§ 60.4375a What reports must I submit?

(a) An owner or operator of a stationary combustion turbine that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, must submit reports of excess emissions and monitor downtime, according to § 60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction.

(b) The notification requirements of § 60.8 apply to the initial and subsequent performance tests.

(c) An owner or operator of an affected facility complying with § 60.4333a(b)(3) must notify the Administrator or delegated authority within 15 calendar days after the facility recommences operation.

(d) An owner or operator of an affected facility complying with § 60.4333a(b)(4) must notify the Administrator or delegated authority within 15 calendar days after the facility has operated more than 168 operating hours since the date the previous performance test was required to be conducted.

(e) Within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a relative accuracy test audit (RATA), you must submit the results following the procedures specified in paragraph (g) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format.

(f) You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqps_cbi@epa.gov*, and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqps_cbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure*, you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.*, hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.*, large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

(j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

§ 60.4380a How are NO*X* excess emissions and monitor downtime reported?

(a) For a stationary combustion turbine that uses water or steam to fuel ratio monitoring and is subject to the reporting requirements under § 60.4375a(a), periods of excess emissions and monitor downtime must be reported as specified in paragraphs (a)(1) through (3) of this section.

(1) An excess emission that must be reported is any operating hour for which the 4-operating-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, is less than the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320a, as established during the most recent performance test. Any operating hour during which no water or steam is injected into the turbine when the specific conditions require water or steam injection for NO*X* control will also be considered an excess emission.

(2) A period of monitor downtime that must be reported is any operating hour in which water or steam is injected into the turbine, but the parametric data needed to determine the steam or water to fuel ratio are unavailable or out-of-control.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the stationary combustion turbine load during each excess emission.

(b) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (b)(1) and (2) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating-hour average NO*X* emissions rate, 30-operating-day rolling average NO*X* emissions rate, 4-hour mass-based emissions rate, or the 12-calendar-month mass-based emissions rate exceeds the applicable emissions standard in § 60.4320a as determined in § 60.4350a.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: NO*X* concentration, CO*2* or O*2* concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

(c) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using combustion parameters or parameters that document proper operation of the NO*X* emission controls excess emissions and monitor downtime are reported as specified in paragraphs (c)(1) and (2) of this section.

(1) Excess emissions that must be reported are each 4-operating-hour rolling average in which any monitored parameter (as averaged over the 4-operating-hour period) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) Periods of monitor downtime that must be reported are each operating hour in which any of the required parametric data that are used to calculate the emission rate, as applicable, used to determine compliance, are either not recorded or are out-of-control.

§ 60.4385a How are SO*2* excess emissions and monitor downtime reported?

(a) If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitor downtime are defined as follows:

(1) For samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, excess emissions occur each operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the stationary combustion turbine exceeds the applicable standard and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur standard.

(2) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (*i.e.*, daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent, 0.15 weight percent, or 0.40 weight percent as applicable. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been combusted, you may resume using the as-delivered sampling option.

(3) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(b) If you choose the option to maintain records of the fuel sulfur content, excess emissions are defined as any period during which you combust a fuel that you do not have appropriate fuel records or that fuel contains sulfur greater than the applicable standard.

(c) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (c)(1) and (2) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating-hour or 30-operating-day rolling average SO*2* emissions rate exceeds the applicable emissions standard in § 60.4330a as determined in § 60.4374a.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: SO*2* concentration, CO*2* or O*2* concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

§ 60.4390a What records must I maintain?

(a) You must maintain records of your information used to demonstrate compliance with this subpart as specified in § 60.7.

(b) An owner or operator of a stationary combustion turbine that uses the other fuels, part-load, or low temperature NO*X* standards in the compliance demonstration must maintain concurrent records of the hourly heat input, percent load, ambient temperature, and emissions data as applicable.

(c) An owner or operator of a stationary combustion turbine that uses the tuning NO*X* standard in the compliance demonstration must identify the hours on which the maintenance was performed and a description of the maintenance.

(d) An owner or operator of a stationary combustion turbine that demonstrates compliance using the output-based standard must maintain concurrent records of the total gross or net energy output and emissions data.

(e) An owner or operator of a stationary combustion turbine that demonstrates compliance using the water or steam to fuel ratio or a parameter continuous monitoring system must maintain continuous records of the appropriate parameters.

(f) An owner or operator of a stationary combustion turbine complying with the fuel-based SO*2* standard must maintain records of the results of all fuel analyses or a current, valid purchase contract, tariff sheet, or transportation contract.

§ 60.4395a When must I submit my reports?

Consistent with § 60.7(c), all reports required under § 60.7(c) must be electronically submitted via CEDRI by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400a How do I conduct performance tests to demonstrate compliance with my NO*X* emissions standard if I do not have a NO*X* CEMS?

(a) You must conduct the performance test according to the requirements in § 60.8 and paragraphs (b) through (d) of this section.

(b) You must use the methods in either paragraph (b)(1) or (2) of this section to measure the NO*X* concentration for each test run.

(1) Measure the NO*X* concentration using EPA Method 7E in appendix A-4 to this part, EPA Method 20 in appendix A-7 to this part, EPA Method 320 in appendix A to part 63 of this chapter, or ASTM D6348-12 (Reapproved 2020) (incorporated by reference, see § 60.17). For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 to this part, and measure and record the electrical and thermal output from the unit. Then, use equation 1 to this paragraph (b)(1) to calculate the NO*X* emissions rate:

Equation 1 to Paragraph (b)(1)

(2) Measure the NO*X* and diluent gas concentrations using either EPA Method 7E in appendix A-4 to this part and EPA Method 3A in appendix A-2 to this part, or EPA Method 20 in appendix A-7 to this part. In addition, when only natural gas is being combusted ASTM D6522-20 (incorporated by reference, see § 60.17) can be used instead of EPA Method 3A in appendix A-2 to this part or EPA Method 20 in appendix A-7 to this part to determine the oxygen content in the exhaust gas. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O*2* or CO*2* CEMS along with a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard measure the electrical, mechanical, and thermal output of the unit. Use EPA Method 19 in appendix A-7 to this part to calculate the NO*X* emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2 and 3 in § 60.4350a(f) to calculate the NO*X* emissions rate in lb/MWh.

(c) You must use the methods in either paragraph (c)(1) or (2) of this section to select the sampling traverse points for NO*X* and (if applicable) diluent gas.

(1) You must select the sampling traverse points for NO*X* and (if applicable) diluent gas according to EPA Method 20 in appendix A-7 to this part or EPA Method 1 in appendix A-1 to this part (non-particulate procedures) and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(2) As an alternative to paragraph (c)(1) of this section, you may select the sampling traverse points for NO*X* and (if applicable) diluent gas according to requirements in paragraphs (c)(2)(i) and (ii) of this section.

(i) You perform a stratification test for NO*X* and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) in appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, you use the following alternative sample point selection criteria for the performance test specified in paragraphs (c)(2)(ii)(A) through (C) of this section.

(A) If each of the individual traverse point NO*X* concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.5 percent CO*2* (or O*2*) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO*X* concentration during the stratification test; or

(B) For a stationary combustion turbine subject to a NO*X* emissions standard greater than 15 ppm at 15 percent O*2*, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO*X* concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.3 percent CO*2* (or O*2*) from the mean for all traverse points; or

(C) For a stationary combustion turbine subject to a NO*X* emissions standard less than or equal to 15 ppm at 15 percent O*2*, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO*X*

concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(d) The performance test must be done at any load condition within ±30 percent of 100 percent of the base load rating. You may perform testing at the highest achievable load point, if at least 70 percent of the base load rating cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both natural gas and fuels other than natural gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle or CHP combustion turbine with supplemental heat (duct burner), you must measure the total NO_X emissions downstream of the duct burner. The duct burner must be in operation within ±30 percent of 100 percent of the base load rating of the duct burners or the highest achievable load if at least 70 percent of the base load rating of the duct burners cannot be achieved during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335a, then that monitoring system must be operated concurrently with each EPA Method 20 in appendix A-7 to this part or EPA Method 7E in appendix A-4 to this part run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320a NO_X emissions standard.

(4) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in § 60.4405a) as part of the initial performance test of the affected unit.

(5) The ambient temperature must be greater than 0 °F during the performance test. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

[91 FR 1985, Jan. 15, 2026, as amended at 91 FR 43567, July 16, 2026]

§ 60.4405a How do I conduct a performance test if I use a NO_X CEMS?

(a) If you use a CEMS the performance test must be performed according to the procedures specified in paragraph (b) of this section.

(b) The initial performance test must use the procedure specified in paragraphs (b)(1) through (4) of this section.

(1) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within ±30 percent of 100 percent of the base load rating while the source is combusting the fuel that is a normal primary fuel for that source. You may perform testing at the highest achievable load point, if at least 70 percent of the base load rating cannot be achieved in practice. The ambient temperature must be greater than 0 °F during the RATA runs. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

(2) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard, measure the electrical and thermal output from the unit.

(3) Use the test data both to demonstrate compliance with the applicable NO_X emissions standard under § 60.4320a and to provide the required reference method data for the RATA of the CEMS described under § 60.4342a.

(4) Compliance with the applicable emissions standard in § 60.4320a is achieved if the sum of the NO_X emissions divided by the heat input (or gross or net energy output) for all the RATA runs, expressed in units of lb/MMBtu, ppm, lb/MWh, or kgs, does not exceed the emissions standard.

[91 FR 1985, Jan. 15, 2026, as amended at 91 FR 43567, July 16, 2026]

§ 60.4415a How do I conduct performance tests to demonstrate compliance with my SO_2 emissions standard?

(a) If you are an owner or operator of an affected facility complying with the fuel-based standard, you may submit fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) to satisfy the requirements of § 60.8.

(b) If you are an owner or operator of an affected facility complying with the SO_2 emissions standard and are not using fuel records, you must conduct the performance test by measuring the SO_2 emissions in the stationary combustion turbine exhaust gases using the methods in either paragraph (b)(1) or (2) of this section.

(1) Measure the SO_2 concentration using EPA Method 6, 6C, or 8 in appendix A-4 to this part or EPA Method 20 in appendix A-7 to this part. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 to this part, and measure and record the electrical and thermal output from the unit. Then use equation 1 to this paragraph (b)(1) to calculate the SO_2 emissions rate:

Equation 1 to Paragraph (b)(1)

(2) Measure the SO_2 and diluent gas concentrations, using either EPA Method 6, 6C, or 8 in appendix A-4 to this part and EPA Method 3A in appendix A-2 to this part, or EPA Method 20 in appendix A-7 to this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O_2 or CO_2 CEMS along with a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output based standard measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A-7 to this part to calculate the SO_2 emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2, 3, and 4 in § 60.4374a to calculate the SO_2 emissions rate in lb/MWh.

[91 FR 1985, Jan. 15, 2026, as amended at 91 FR 43567, July 16, 2026]

Other Requirements and Information

§ 60.4416a What parts of the general provisions apply to my affected EGU?

(a) Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 2 to this subpart, do not apply to your affected combustion turbine.

(b) Small, medium, and low utilization large combustion turbines that are subject to this subpart and are not a “major source” or located at a “major source” (as that term is defined at 42 U.S.C. 7661(2)) are exempt from the requirements of 42 U.S.C. 7661a(a).

§ 60.4417a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your State, local, or Tribal agency. If the Administrator has delegated authority to your State, local, or Tribal agency, then that agency, (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if 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, the Administrator retains the authorities listed in paragraphs (b)(1) through (6) of this section and does not transfer them to the State, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emissions standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

§ 60.4420a What definitions apply to this subpart?

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

Base load rating means 100 percent of the manufacturer's design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel. The base load rating does not include any potential heat input to an HRSG.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Byproduct means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, pulp and paper mills, or other industrial facilities (except natural gas and fuel oil).

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to generate steam that is used to create additional electric power output in a steam turbine.

Combined heat and power (CHP) combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to heat water or another medium, generate steam for useful purposes other than exclusively for additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine engine means the air compressor, combustor, and turbine sections of a stationary combustion turbine.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 or 2, as defined in ASTM D396-98 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined in ASTM D975-08a (incorporated by reference, see § 60.17), kerosene, as defined in ASTM D3699-08 (incorporated by reference, see § 60.17), biodiesel as defined in ASTM D6751-11b (incorporated by reference, see § 60.17), or biodiesel blends as defined in ASTM D7467-10 (incorporated by reference, see § 60.17).

District energy system means a central plant producing hot water, steam, and/or chilled water, which then flows through a network of insulated pipes to provide hot water, space heating, and/or air conditioning for commercial, institutional, or residential buildings.

Dry standard cubic foot (dscf) means the quantity of gas, free of uncombined water, that would occupy a volume of 1 cubic foot at 293 Kelvin (20 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

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

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire (*e.g.*, firefighting turbine) or flood, etc. Emergency combustion turbines may be operated for maintenance checks and readiness testing to retain their status as emergency combustion turbines, provided that the tests are recommended by Federal, State, or local government, agencies, or departments, voluntary consensus standards, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the combustion turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines. Emergency combustion turbines do not include combustion turbines used as peaking units at electric utilities or combustion turbines at industrial facilities that typically operate at low capacity factors.

Excess emissions means a specified averaging period over which either:

(1) The NO*X* or SO*2* emissions rate are higher than the applicable emissions standard in § 60.4320a or § 60.4330a;

(2) The total sulfur content of the fuel being combusted in the affected facility or the SO*2* emissions exceeds the standard specified in § 60.4330a; or

(3) The recorded value of a particular monitored parameter, including the water or steam to fuel ratio, is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator or delegated authority, including the requirements of this part and part 61 of this chapter, requirements within any applicable State Implementation Plan, and any permit requirements established under § 52.21 or §§ CFR 51.18 and 51.24 of this chapter.

Firefighting combustion turbine means any stationary combustion turbine that is used solely to pump water for extinguishing fires.

Fuel oil means a fluid mixture of hydrocarbons that maintains a liquid state at ISO conditions. Additionally, fuel oil must meet the definition of either distillate oil (as defined in this subpart) or liquefied petroleum (LP) gas as defined in ASTM D1835-03a (incorporated by reference, see § 60.17).

Garrison facility means any permanent military installation.

Gross energy output means:

(1) For simple cycle and combined cycle combustion turbines, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s).

(2) For a CHP combustion turbine, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

(3) For a CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of useful thermal output on a 12-calendar-month basis, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

(4) For a district energy CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of useful thermal output on a 12-calendar-month basis, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative

to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*e.g.*, steam delivered to an industrial process) divided by 0.95.

Heat recovery steam generating unit (HRSG) means a unit where the hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners. A heat recovery steam generating unit operating independent of the combustion turbine engine may operate burners using ambient air.

Integrated gasification combined cycle electric utility steam generating unit (IGCC) means an electric utility steam generating unit that combusts solid-derived fuels in a combined cycle combustion turbine. No solid fuel is directly combusted in the unit during operation.

ISO conditions mean 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity, and 101.325 kilopascals (14.69 psi, 1 atm) pressure.

Large combustion turbine means a stationary combustion turbine with a base load rating greater than 850 MMBtu/h of heat input.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Low-Btu gas means biogas or any gas with a heating value of less than 26 megajoules per standard cubic meter (MJ/scm) (700 Btu/scf).

Medium combustion turbine means a stationary combustion turbine with a base load rating greater than 50 MMBtu/h and less than or equal to 850 MMBtu/h of heat input.

Natural gas means a fluid mixture of hydrocarbons, composed of at least 70 percent methane by volume, that has a gross calorific value between 35 and 41 MJ/scm (950 and 1,100 Btu/scf), and that maintains a gaseous state under ISO conditions. Unless processed to meet this definition of natural gas, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO*2* content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.*, auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.*, the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility plus 100 percent of the useful thermal output; or

(2) For CHP facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-calendar-month rolling average basis, the net electric or mechanical output from the affected turbine divided by 0.95, plus 100 percent of the useful thermal output.

(3) For district energy CHP facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-calendar-month rolling average basis, the net electric or mechanical output from the affected turbine divided by 0.95, plus 100 percent of the useful thermal output divided by 0.95.

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

Offshore turbine means a stationary combustion turbine located on a platform or facility in an ocean, territorial sea, the outer continental shelf, or the Great Lakes of North America and stationary combustion turbines located in a coastal management zone and elevated on a platform.

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

Operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, the operating hour is a full operating hour. If the unit combusts fuel for only part of the clock hour, the operating hour is a partial operating hour.

Out-of-control period means any period beginning with the hour corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the hour corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself.

Small combustion turbine means a stationary combustion turbine with a base load rating less than or equal to 50 MMBtu/h of heat input.

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard cubic foot (scf) means the quantity of gas that would occupy a volume of 1 cubic foot at 293 Kelvin (20.0 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Standard cubic meter (scm) means the quantity of gas that would occupy a volume of 1 cubic meter at 293 Kelvin (20.0 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Stationary combustion turbine means all equipment including, but not limited to, the combustion turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except post combustion emissions control equipment), heat recovery system (including heat recovery steam generators and duct burners); steam turbine; fuel compressor and/or pump, any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system; plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine (*e.g.*, onsite photovoltaics), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. Portable combustion turbines are excluded from the definition of "stationary combustion turbine," and not regulated under this part, if the combustion turbine meets the definition of "nonroad engine" under title II of the Clean Air Act and applicable regulations and is certified to meet emissions standards and all related requirements promulgated pursuant to title II of the Clean Air Act.

Temporary combustion turbine means a combustion turbine that is intended to and remains at a single stationary source (or group of stationary sources located within a contiguous area and under common control) for 24 consecutive months or less.

Turbine tuning means planned maintenance or parameter performance testing of a combustion turbine engine involving adjustment of the operating configuration to maintain proper combustion dynamics or testing machine operating performance. Turbine tuning is limited to 30 hours per 12-calendar-month period.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.*, steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation or mechanical output at the affected facility to directly enhance the performance of the affected facility (*e.g.*, economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output) or to supply energy to a pollution control device at the affected facility (*e.g.*, steam provided to a carbon capture system would not be considered useful thermal output). Useful thermal output for affected facilities with no condensate return (or other thermal energy input to affected facilities) or where measuring the energy in the condensate (or other thermal energy input to the affected facilities) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions (*e.g.* liquid water). Affected facilities with meaningful energy in the condensate return (or other thermal energy input to the affected facility) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Utilization means the ratio between the actual heat input to a combustion turbine engine (not including any heat input to an HRSG) during a 12-calendar-month period and the potential heat input to the combustion turbine engine had it operated at the base load rating for every hour during the 12-calendar-month period. Heat input during a system emergency as defined in this section is excluded when determining the utilization rate. Actual and potential heat input derived from non-combustion sources (*e.g.*, solar thermal) are not included when calculating the utilization.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to this part or part 75 of this chapter as applicable. For CEMS maintained according to part 75, the initial certification requirements in § 75.20 and appendix A to part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 must be met. For fuel flow meters maintained according to part 75, the initial certification requirements in section 2.1.5 of appendix D to part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters). Any out-of-control data is not considered valid data.

[91 FR 1985, Jan. 15, 2026, as amended at 91 FR 43567, July 16, 2026]

Table 1 to Subpart KKKKa of Part 60—Nitrogen Oxide Emission Standards for Stationary Combustion Turbines

Combustion turbine type	**Combustion turbine base load rated heat input (HHV)**	**Input-based NO_X emission standard 1**	**Optional output-based NO_X standard 2**
New, firing natural gas with utilization rate >45 percent	>850 MMBtu/h	5 ppm at 15 percent O_2 or 7.9 ng/J (0.018 lb/MMBtu)	0.054 kg/MWh-gross (0.12 lb/MWh-gross) 0.055 kg/MWh-net (0.12 lb/MWh-net).

New, firing natural gas with utilization rate ≤45 percent and with design efficiency ≥38 percent	>850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net).
New, firing natural gas with utilization rate ≤45 percent and with design efficiency <38 percent	>850 MMBtu/h	9 ppm at 15 percent O_2 or 14 ng/J (0.033 lb/MMBtu)	0.17 kg/MWh-gross (0.37 lb/MWh-gross) 0.17 kg/MWh-net (0.38 lb/MWh-net).
New, modified, or reconstructed, firing non-natural gas	>850 MMBtu/h	42 ppm at 15 percent O_2 or 70 ng/J (0.16 lb/MMBtu)	0.45 kg/MWh-gross (1.0 lb/MWh-gross) 0.46 kg/MWh-net (1.0 lb/MWh-net).
Modified or reconstructed, firing natural gas, at all utilization rates, with design efficiency ≥38 percent	>850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net).
Modified or reconstructed, firing natural gas, at all utilization rates, with design efficiency <38 percent	>850 MMBtu/h	15 ppm at 15 percent O_2 or 24 ng/J (0.055 lb/MMBtu)	0.28 kg/MWh-gross (0.62 lb/MWh-gross) 0.29 kg/MWh-net (0.30 lb/MWh-net).
New, firing natural gas, at utilization rate >45 percent	>50 MMBtu/h and ≤850 MMBtu/h	15 ppm at 15 percent O_2 or 24 ng/J (0.055 lb/MMBtu)	0.20 kg/MWh-gross (0.43 lb/MWh-gross) 0.20 kg/MWh-net (0.44 lb/MWh-net).
New, firing natural gas, at utilization rate ≤45 percent	>50 MMBtu/h and ≤850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.54 kg/MWh-gross (1.2 lb/MWh-gross) 0.56 kg/MWh-net (1.2 lb/MWh-net).
Modified or reconstructed, firing natural gas	>20 MMBtu/h and ≤850 MMBtu/h	42 ppm at 15 percent O_2 or 67 ng/J (0.15 lb/MMBtu)	0.91 kg/MWh-gross (2.0 lb/MWh-gross) 0.92 kg/MWh-net (2.0 lb/MWh-net).
New, firing non-natural gas	>50 MMBtu/h and ≤850 MMBtu/h	74 ppm at 15 percent O_2 or 120 ng/J (0.29 lb/MMBtu)	1.6 kg/MWh-gross (3.6 lb/MWh-gross) 1.6 kg/MWh-net (3.7 lb/MWh-net).
Modified or reconstructed, firing non-natural gas	>20 MMBtu/h and ≤850 MMBtu/h	96 ppm at 15 percent O_2 or 160 ng/J (0.37 lb/MMBtu)	2.1 kg/MWh-gross (4.7 lb/MWh-gross) 2.2 kg/MWh-net (4.8 lb/MWh-net).
New, firing natural gas	≤50 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.64 kg/MWh-gross (1.4 lb/MWh-gross) 0.65 kg/MWh-net (1.4 lb/MWh-net).
New, firing non-natural gas	≤50 MMBtu/h	96 ppm at 15 percent O_2 or 160 ng/J (0.37 lb/MMBtu)	2.4 kg/MWh-gross (5.3 lb/MWh-gross) 2.5 kg/MWh-net (5.4 lb/MWh-net).
Modified or reconstructed, all fuels	≤20 MMBtu/h	150 ppm at 15 percent O_2 or 240 ng/J (0.55 lb/MMBtu)	3.9 kg/MWh-gross (8.7 lb/MWh-gross) 4.0 kg/MWh-net (8.9 lb/MWh-net).
New, firing natural gas, either offshore turbines and/or turbines bypassing the heat recovery unit	>50 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	N/A.
Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0 °F (−18 °C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating	≤30 MW output	150 ppm at 15 percent O_2 or 240 ng/J (0.55 lb/MMBtu)	N/A.
Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0 °F (−18 °C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating	> 30 MW output	96 ppm at 15 percent O_2 or 150 ng/J (0.35 lb/MMBtu)	N/A.

Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 86 ng/J (0.20 lb/MMBtu)	N/A.
Temporary turbines firing natural gas	≤850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	N/A.
Temporary turbines firing non-natural gas	≤850 MMBtu/h	74 ppm at 15 percent O_2 or 120 ng/J (0.29 lb/MMBtu)	N/A.

1 Input-based standards are determined on a 4-operating-hour rolling average basis.

2 Output-based standards are determined on a 30-operating-day average basis.

[91 FR 43568, July 16, 2026]

Table 2 to Subpart KKKKa of Part 60—Alternative Mass-Based NO_X Emission Standards for Stationary Combustion Turbines

Combustion turbine type	4-Hour emissions rate (lb NO_X/MW-rated output)	12-Calendar-month emissions rate (ton NO_X/MW-rated output)
Natural Gas	0.38 kg NO_X/MW-rated output (0.83 lb NO_X/MW-rated output)	0.44 tonne NO_X/MW-rated output (0.48 ton NO_X/MW-rated output).
Non-Natural Gas	0.82 kg NO_X/MW-rated output (1.8 lb NO_X/MW-rated output)	0.74 tonne NO_X/MW-rated output (0.81 ton NO_X/MW-rated output).

Table 3 to Subpart KKKKa of Part 60—Applicability of Subpart A of This Part to This Subpart

General provisions citation	Subject of citation	Applies to subpart KKKKa	Explanation
§ 60.1	Applicability	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4420a.
§ 60.3	Units and Abbreviations	Yes	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	Yes	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§ 60.8(c)	Conducting performance tests	No	Overridden by § 60.4320a(d).
§ 60.8(d)-(f)	Conducting performance tests	Yes	
§ 60.9	Availability of Information	Yes	
§ 60.10	State authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	
§ 60.12	Circumvention	Yes	
§ 60.13(a)-(h), (j)	Monitoring requirements	Yes	
§ 60.13(i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	No	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	Yes	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 of this chapter or to information reported through ECMPS.

Appendix L

40 CFR Part 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Source:89 FR 40035, May 9, 2024, unless otherwise noted.

Applicability

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that combusts coal and that commences modification after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (8) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

Emission Standards

§ 60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and Title V thresholds for greenhouse gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under

the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

§ 60.5520a What CO*2* emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO*2* in excess of the applicable CO*2* emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term "gross or net energy output" is used, the term that applies to you is "gross energy output."

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term "gross or net energy output" is used, the term that applies to you is "net energy output." Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO*2*/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO*2*/MMBtu) or less (e.g., non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO*2* emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO*2* emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO*2* emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO*2* emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO*2* emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined

(HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Where:

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Where:

(ii) For intermediate load combustion turbines:

Where:

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.*, no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program.

(2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO*2* emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO*2* in excess of 230 lb CO*2*/MMBtu.

Monitoring and Compliance Determination Procedures

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO*2* emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO*2* mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)).

(b) You must determine the hourly CO*2* mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO*2* continuous emission monitoring system (CEMS) to directly measure and record hourly average CO*2* concentrations in the

affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO*2* concentration, provided that your EGU does not use carbon separation (*e.g.*, carbon capture and storage), you may use data from a certified oxygen (O2) monitor to calculate hourly average CO*2* concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO*2* concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO*2* mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO*2* mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO*2* mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for "valid operating hours", as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO*2* mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to 40 CFR part 75 (if CO*2* concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO*2* concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO*2* mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO*2*.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO*2* to kg. Round off to the nearest kg.

(iv) The hourly CO*2* tons/h values and EGU (or stack) operating times used to calculate CO*2* mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO*2* mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO*2* mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO*2* mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to 40 CFR part 75 to calculate the hourly CO*2* mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F-7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G-4 nomenclature.

(3) For each "valid operating hour" (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO*2* mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO*2*. Then, multiply the result by 907.2 to convert from tons of CO*2* to kg. Round off to the nearest two significant figures.

(4) The hourly CO*2* tons/h values and EGU (or stack) operating times used to calculate CO*2* mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO*2* mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO*2* emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO*2* emissions using Equation G-4 in appendix G to 40 CFR part 75.

(ii) You may use the procedure for determining CO*2* emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3).

(d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.*, lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.*, hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.*, lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to 40 CFR part 75;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of 40 CFR part 98. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to 40 CFR part 75.

(e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as “stack operating hours” (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or

(2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the “stack operating time” (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.*, either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion

(*e.g.*, blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO*2* present in the fuel prior to combustion and exclude this portion of the CO*2* mass emissions from compliance determinations.

(1) Each compliance period shall include only "valid operating hours" in the compliance period, *i.e.*, operating hours for which:

(i) "Valid data" (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO*2* mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO*2* mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO*2* mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output (P*gross/net*) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO*2* mass emissions by summing the valid hourly CO*2* mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO*2* mass emissions, you must determine P*gross/net* (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO*2* mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO*2* mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate P*gross/net* for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Where:

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Where:

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.*, denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO*2* mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO*2* mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO*2* mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO*2* mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(8) You may exclude CO*2* mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in §

60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section.

(i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu.

(b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following:

(1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall:

(i) Identify each affected unit for which you are seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart;

(iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including;

(A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable;

(B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include:

(A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart;

(B) Documentation of any permit delays; or

(C) Documentation of delays in construction or permitting of infrastructure (*e.g.*, CO_2 pipelines) that is necessary for implementation of the control technology;

(v) Identify a proposed compliance date no later than one year after the applicable compliance date listed in table 1 to this subpart.

(2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included:

(i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU.

(ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.

Notification, Reports, and Records

§ 60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart).

(b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.

§ 60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.*, the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.*, beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2

mass emission rates are calculated using maximum potential values are not “valid operating hours” (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO*2* to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO*2* to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO*2* to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO*2* from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO*2* as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO*2*, and permanence of the CO*2* storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO*2* without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO*2* or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under 40 CFR 75.53(g) and (h);

(ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4);

(iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate;

(iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO*2* concentration monitoring systems or O2 monitors used to calculate CO*2* concentration;

(vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e).

(c) You must keep records of the calculations you performed to determine the hourly and total CO*2* mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

§ 60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or Tribal agency. If the Administrator has delegated authority to your state, local, or Tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if 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, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580a What definitions apply to this subpart?

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

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.*, solar thermal) are not included when calculating the annual capacity factor.

Base load combustion turbine means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.*, solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite in ASTM D388-99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose 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 included in this definition for the purposes of this subpart.

Coal-fired Electric Generating Unit means a steam generating unit or integrated gasification combined cycle unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit*, (also known as “cogeneration”) means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.*, electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.*, CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22-2014, ASME PTC 46-1996, ISO 2314:2009 (E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator. When determining the design efficiency, the output of integrated equipment and energy storage are included.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396-98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975-08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699-08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751-11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467-10 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.*, meets the applicability criteria).

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

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

Intermediate load combustion turbine means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has 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), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.*, auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.*, CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.*, a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-

combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, (*e.g.*, onsite photovoltaics), integrated energy storage (*e.g.*, onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP-011-2 or its successor.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.*, steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.*, economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO*2* emissions rate is higher than the applicable emissions standard located in table 1 to this subpart.

Table 1 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	**CO_2 emission standard**
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
	For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

Table 2 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Steam Generating Units or IGCC That Commenced Modification After May 23, 2023

Affected EGU	**CO_2 Emission standard**
Modified coal-fired steam generating unit	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification).

Table 3 to Subpart TTTTa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§ 60.8(c)-(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)-(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines).	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.